Exhibit No.___(DWS-1T)
Docket No. UE-111190
Witness: Donald W. Schoenbeck

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant,	)	Docket Nos. UE-111190
v.	)	
PACIFICORP D/B/A PACIFIC POWER, Respondent.	)	

RESPONSIVE TESTIMONY OF DONALD W. SCHOENBECK

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

January 6, 2012

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 PacifiCorp (the "Company").

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. This testimony will address certain power supply matters. These items are the updating of power costs to take into account information provided by the Company in response to data requests, using forward prices from over a longer period of time for deriving power supply costs, and the use of an alternate power supply model instead of the internally developed Company model ("GRID") in future proceedings. In addition, my associate remove $4.9 million of revenue associated with this contract from the test period. See Exhibit ___ (RBD-3), Tab 3, page 3.0.1. The Company's initial update for the SCL contract in its response to WUTC DR 101 only included the impact of this contract on the Company's net power supply cost. As this contract is providing integration services to SCL, the revenues associated with this contract must be taken into account in order to determine the allowed revenue increase in this proceeding. Confidential Exhibit ___ (DWS-5C) is an excerpt of the Company's second supplemental data response to WUTC DR 101. This exhibit indicates a revenue projection attributable to this contract of $9.4 million for the rate year. Instead of removing $4.9 million from the test period as the Company had done, $4.5 million of revenue needs to be added to the test period to achieve the total amount of expected revenue under the new agreement ($4.5 + $4.9 = $9.4 million). The Washington allocated revenue requirement impact from incorporating the revenue from the new contract is $2.2 million ($9.4 million x 22.47% x 1.048 = $2.2 million).

Bridger Coal Costs

Q. PLEASE PROVIDE A BRIEF EXPLANATION OF HOW THE JIM BRIDGER COAL PLANT PROCURES ITS FUEL.

A. The Bridger plant receives its fuel from two sources. As noted in the Company's testimony, about 31% of the coal needs come from a third party coal source, the Black Butte mine. The remaining need is satisfied from an affiliated source, the Bridger Coal Company ("BCC"). Through an affiliate, PacifiCorp owns 66.67% of BCC, while the remainder is owned by an affiliate of the Idaho Power Company.

Q. HOW SHOULD THE BRIDGER COAL COST BE DETERMINED FOR RATE MAKING PURPOSES?

A. The coal sourced from the Black Butte mine should be evaluated and assessed under the usual rate setting standard of whether or not the cost is prudent or reasonable. For the coal sourced from the Company affiliate however, a different standard is warranted. For affiliated coal costs the standard should be the lower of the market value or actual cost. By establishing the affiliated cost in this manner, ratepayers are protected from affiliate abuse by the Company paying an unreasonable price which would allow the affiliate and parent corporation to achieve above market profits.

Q. IS MARKET PRICE INFORMATION READILY AVAILABLE FOR COAL NEAR THE BRIDGER FACILITY?

A. No. There is no readily available source for coal costs near and around the Bridger facility. This makes it extremely difficult to ascertain the reasonableness of the Company's affiliated coal price for Bridger.

Q. YOU STATED EARLIER THAT YOU OBJECTED TO THE COMPANY'S COAL COST UPDATES REFLECTED IN WUTC DR 91 AND DR 101. PLEASE EXPLAIN WHY THIS IS THE CASE.

A. The Company provided limited workpapers associated with the coal cost updates less than two weeks before the testimony was due. The Bridger coal cost reflected in the updated filing is about 16% greater than the 2010 cost as reflected in the Company's FERC Form 1. In other words, to achieve the coal costs the Company is seeking for the Bridger plant in the updated filing for the rate year, it would have to experience 6.4% cost increases in each year of 2011, 2012, and 2013. This seems extraordinarily high and well above projected escalation rates. In addition, several of the workpaper files contained many "pasted values" instead of formulas. This makes it very difficult and time consuming to track through and audit any changes in the Company's calculations. Given the timing and lack of documentation, it was impossible to ascertain the reasonableness of the Company's rate year coal price update for BCC when no readily available third party source of market prices could be used as a measuring stick.

Q. WHAT ANALYSIS HAD YOU UNDERTAKEN WITH RESPECT TO THE COMPANY'S ORIGINAL CLAIMED COAL COSTS?

A. We had examined the historical fuel costs as reflected in the FERC Form 1 filings of the Company for the past several years, the Company's Excel spreadsheet files in support of the claimed coal cost and the coal costs reflected in the Company's compliance filing in UE-100749. In this assessment, the most critical factor was that in the last proceeding, the cost of coal from BCC was less than the cost of coal supplied from the Black Butte mine. That is not the instant case where the Company's claimed cost of BCC coal is greater than projected Black Butte cost. Also, under the Company's updated cost contained in WUTC DR 101, the one year escalation of BCC costs from the 2010 compliance filing is incredible at 21%. This is shown in the following table which also presents a comparison of the projected cost of coal from the two Bridger sources at various points in time.

Comparison of Coal Costs (\$/MMBTU)

Source	2010 GRC (4/11 - 3/12)	2011 GRC As Filed (6/12 - 5/13)	2011 GRC WUTC 101 Update	Difference	Percent
BBC	\$1.66	\$1.91	\$2.00	\$0.34	21%
Black Butte	\$1.75	\$1.84	\$1.90	\$0.15	8%
Blended	\$1.69	\$1.89	\$1.97	\$0.28	16%
Difference:	-\$0.09	\$0.06	\$0.11	\$0.20	12%

Q. WHAT IS THE ICNU RECOMMENDATION FOR ESTABLISHING THE COST OF BRIDGER COAL IN THIS PROCEEDING?

A. At this time, I recommend that the updated price of coal from the Black Butte mine be used as the Bridger coal cost for ratemaking purposes. I fully understand that this is a very limited measure of market value but it does represent a significant source of coal already for the Bridger plant. This recommendation also satisfies the standard that the cost of coal from an affiliate be no higher than the market value. Under this recommendation, the coal cost for Bridger is $1.895 per MMBTU. A value quite close to the original as filed blended cost of $1.886 per MMBTU. Incorporating this recommendation into the Company's WUTC DR 101 GRID simulation lowers the WCA NPC by $6.9 million. This lowers the Company's claimed revenue increase by about $1.6 million. ICNU reserves the right to provide supplemental testimony on this issue, given the tardiness with which the Company provided workpapers in support of its coal cost update. The Commission should also not consider any justifications for this increase in PacifiCorp's rebuttal testimony, since the Company could have provided supporting documentation earlier in this proceeding.

<u>Forward Market Price Updates</u>

Q. PLEASE DESCRIBE HOW THE COMPANY DOES ITS MARKET PRICE UPDATES.

A. In performing a market price update, the Company's uses its "Official Forward Price Curve" ("OFFC") in effect at the time of the update for the various critical trading hubs (both electricity and gas). It is my understanding that while the Company has forward price curves for each trading day throughout the month, the OFFC—which undergoes greater review and approval—is compiled once each quarter or as required to determine the Company's net power cost in a rate proceeding. Based on the OFFC, the Company will update all contracts and transactions, including any mark-to-market adjustment, affected by changes in market prices. In addition, the Company will also include any additional short-term transactions it has executed. The following table shows the change in average rate year prices at select trading hubs from the Company's OFFC. The table below illustrates the significant drop in market prices since March 2011:

PacifiCorp Forward Price Comparison June 2012 through May 2013 ($/MWh or $/MMBTU)				
Market	**Mar-11**	**Sep-11**	**Nov-11**	**Change**
Mid-C HLH	$41.44	$36.28	$34.05	-$7.40
Mid-C LLH	$31.44	$26.47	$24.63	-$6.81
COB HLH	$46.11	$40.79	$37.86	-$8.25
COB LLH	$33.35	$28.84	$27.22	-$6.14
Sumas	$4.89	NA	$4.05	-$0.84
AECO	$4.55	NA	$3.78	-$0.77

Q. DO YOU HAVE ANY CONCERNS WITH THE MANNER IN WHICH THE COMPANY PERFORMS ITS MARKET PRICE UPDATES?

A. Yes, I have a concern with a single aspect of PacifiCorp's market update procedures. The concern is PacifiCorp reliance on an OFFC from a single day to determine the expected rate year costs. I am concerned that use of a single day raises the potential for gaming and the Company's approach is quite different from the approach used by both Puget Sound Energy ("PSE") and Avista. For many years, PSE and Avista have used the average of three months of trading days to derive the market prices used in regulatory filings. This has become the accepted method as a result of the rebuttal testimony and accompanying analysis performed by Dr. Jeffrey Dubin on behalf of PSE in docket UE-

040641 and the resulting Commission order accepting this approach for PSE.[1/] The testimony stated that in a less than perfectly efficient market, an average of future prices could be used. Dr. Dubin's accompanying analysis indicated little statistical difference between using averaging periods from one month up to six months for a given future period. Focusing on periods that were five months and seventeen months into the future—to reflect the typical start and end months of the rate year—Dr. Dubin concluded that the use of a three month averaging period was reasonable.

Q. DO YOU BELIEVE THE COMPANY ENTERS INTO TRANSACTIONS IN MARKETS THAT ARE NOT "PERFECTLY EFFICIENT"?

A. Yes, as measured by liquidity. There are several market hubs where readily available daily forward market price information is not readily available. For example, under the WCA power supply approach, forward price information is required for the COB and Four Corners market hubs. However, forward prices are not reported by the Intercontinental Exchange ("ICE") at either of these locations due to illiquidity.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. The Commission should require PacifiCorp to use the average of many trading days to derive the forward price curves. While ICNU prefers the use of three months of trading days, consistent with the method used by PSE and Avista, PacifiCorp's expansive service territory requires far more electricity trading hubs than either PSE or Avista, in order to determine the net power supply costs for the Company. For this reason, the Commission should require that forward prices be determined using the average of all trading days

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1/ WUTC v. PSE, Docket Nos. UE-040641 and UG-040640, Rebuttal Testimony of Dr. Jeffrey A. Dubin at 23:7-17 (Nov. 3, 2004); WUTC v. PSE, Docket Nos. UE-040641 and UG-040640, Order No. 06 ¶ 111 (Feb. 18, 2005).

from the most recent month or 30 day period. Typically, this would be 20-22 trading days. Of course, ICNU would also support using three months as is done by PSE and Avista. Either approach would give greater assurance to ratepayers than the Company's single day method.

Q. HAVE YOU PERFORMED ANY ANALYSIS SHOWING HOW THIS RECOMMENDATION WOULD IMPACT THE COMPANY'S WCA NPC?

A. Yes. The following table compares the forward market price average for the rate year at select hubs from the Company initial filing and updates along with the ICNU recommendation. The Company OFFCs were as of March 2011 ("As Filed" column), September 2011 ("WUTC 91" column) and November 2011 ("WUTC 101" column). The ICNU prices were derived from ICE forward prices from November 17 through December 16, 2011 for the Mid-C hub and maintaining the Mid-C COB differential from the Company's WUTC DR 101 OFFC in order to derive the ICNU COB prices.

Forward Price Comparison - Rate Year Average ($/MWh or $/MMBTU)

Market Hub	As filed	WUTC 91	WUTC 101	ICNU	ICNU - WUTC 101
Mid-C On peak	$41.44	$36.28	$34.05	$32.51	-$1.54
Mid-C Off peak	$31.44	$26.47	$24.63	$23.64	-$0.99
COB On Peak	$46.11	$40.79	$37.86	$36.33	-$1.54
COB Off Peak	$33.35	$28.84	$27.22	$26.23	-$0.99
Sumas	$4.89	NA	$4.05	$3.83	-$0.22
Chehalis	$5.23	$4.57	$4.34	$4.10	-$0.24

Using the illustrative ICNU market prices, the Company's WCA net power cost is lowered by about $4.2 million. This market price update lowers the Company's claimed Washington increase by about $1.0 million. ICNU recommends that the Commission order the Company to perform a compliance filing in this proceeding using the most currently available forward prices from at least the most recent month. This final update will ensure the rates resulting from this proceeding are based on the most recent forward price information available. This final update can also include the most recent short-term transactions the Company has executed (both electric and gas) and final mark-to-market calculations, but the Company should not have the discretion to change any other contract or cost item that has not been previously approved by this Commission. It would be inappropriate to allow PacifiCorp to change rates based on contracts that have not been reviewed by the parties or the Commission.

Power Supply Mode

Q. DO YOU HAVE ANY OTHER POWER COST RECOMMENDATIONS FOR THE COMMISSION TO CONSIDER?

A. Yes. I believe that the Commission should order the Company to use a power supply model that has been developed and marketed by an independent third party vendor in all future proceeding before this Commission.

Q. WHY?

A. In this proceeding—as it has done in several prior proceedings—the Company has used its GRID model to project its net power cost for the rate year. This is an internally developed Company model with several significant short comings. The GRID model has been controversial in many jurisdictions, with parties litigating numerous GRID modeling problems that overstate net power costs. For example, the Company uses a screening process in order to determine the proper unit commitment as the internal dispatch logic was shown to be deficient. A more robust model would not require this burdensome screening process. Similarly, the Company uses an external model to determine the hourly dispatch of its hydro resources instead of the GRID dispatch logic. PacifiCorp has resisted providing this model to ICNU, and instead only provides model runs to ICNU. (This pre-determined hourly dispatch is then directly inputted into the GRID model through a data file). Since the dispatch of hydro resources should be dependent upon market conditions, the use of the external hydro dispatch model necessitates an iterative process between GRID and the hydro model to capture any market price changes. Again, this iterative process is avoided if the model is actually determining the hydro dispatch and the marginal cost or market price simultaneously. In addition, the GRID model requires that hourly electricity market prices be directly inputted at several trading hubs. This requires the Company to manufacture market prices through an external process as well. The futility of this exercise—projecting hourly "real time" market prices up to seventeen months into the future —is shown by the simple fact that no third party vendor markets projected real-time prices. It simply cannot be done with any reasonable accuracy beyond just a couple of days. Further, as I previously noted, some of the electricity trading hubs are illiquid thereby requiring considerable "guestimating" in order to determine projected forward prices for the rate year.

Many of these model deficiencies can be overcome by simply using a different model. In my view, the GRID model is a very simplistic model that must be told how units should be run and what the market price already is, irrespective of the availability of the generating resources. For example, with the GRID model, a planned outage at a major resource has absolutely no impact on the market price during the outage hours.

This is far from the real world circumstances where outages at significant plants or transmission lines have an immediate impact on market prices.

Q. ARE OTHER MODELS READILY AVAILABLE THAT CAN TAKE IN TO ACCOUNT VARYING MARKET CONDITIONS?

A. Yes. There are several third party models being marketed which could be used to determine the Company's power supply cost through a more appropriate simulation process. For example, this Commission is very familiar with the AURORA model marketed by EPIS. This fundamental model is employed both by PSE and Avista for deriving power supply costs. As a fundamental model, AURORA will determine the hourly market price at reach electricity hub based upon the marginal cost of serving that location at that particular hour. In so doing, it will use all available resources to serve the projected load in a least cost manner. This allows for a more consistent integration of all market drivers based upon a given series of loads and resource costs including forward gas prices. In my view, this would be a far superior method for deriving PacifiCorp's net power supply cost, instead of using the patched-together series of external models and considerable judgment required with GRID.

Q. ARE YOU RECOMMENDING THAT THE COMPANY SHOULD BE REQUIRED TO USE THE AURORA MODEL?

A. No. The Company should be allowed to select an independent model that it believes is most appropriate for modeling its system. However, the Commission should require that Staff and intervening parties be given access to the model at little or no cost and trained in its use, as is done with the Company's current GRID model and PSE's and Avista's AURORA model. This training should occur long before the Company is allowed to submit another rate filing using the new model.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.