BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 227

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2012 Transition Adjustment Mechanism	)
Schedule 201, Cost-Based Supply Service	)

REBUTTAL TESTIMONY OF

DONALD W. SCHOENBECK

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

August 16, 2011

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. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I provided direct testimony in this proceeding on June 24, 2011 and supplemental testimony on July 5, 2011 on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT TOPICS WILL YOUR REBUTTAL TESTIMONY ADDRESS?

A. I will respond to the arguments raised by PacifiCorp (or the "Company") with regard to the recommended ICNU adjustments addressing the Company's load forecast, the execution of the Company's hedging policy, the average energy market sales caps, and the must run designation of the Gadsby units.

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

A. The Company does not operate Gadsby units 4, 5, and 6 as must run plants, and they should not be modeled in the GRID simulation in this manner. The Company cites to the capacity factor of 33% these units had in 2009 to justify the must run designation. However, for the most recent twelve months (July 2010 through June 2011), the capacity factor for these units is only **[Confidential]** [redacted] **[Confidential]**. This low capacity factor confirms the fact that these units are not operated as must run.

The Company claims the hourly market sales cap method used in this case allows for greater market sales than its previous method ("graveyard method") and the ICNU recommendation to eliminate the caps would effectively be double counting its sales transactions. The detailed data the Company provided with its rebuttal filing can be used to show how the hourly energy caps derived under the Company's method are substantially below the actual sales transactions the Company has entered into at each trading hub in every month. It can also be readily shown that the ICNU recommendation does not result in a double counting of sales activity as the historical sales levels the Company has achieved are far beyond the summation of both the GRID modeled short term sales and the arbitrage/trading sales amount. The Oregon Public Utility Commission (the "Commission") should instruct the Company to remove the hourly market sales caps from its GRID simulation.

Much of the Company's rebuttal testimony addresses its current hedging strategy and policy. With regard to the current policy, ICNU has not raised any concerns at this time. ICNU disagrees with how the Company implemented its November 2006 policy ("2006 Policy"). Under the 2006 Policy, the Company entered into too many hedging transactions for too great of a time period. While the Company acknowledges that you cannot "beat the market," that is precisely what it was trying to do in 2007 while using the 2006 Policy. The Company also states both gas and electric hedges need to be considered together. ICNU agrees. However, the Company engaged in only a very limited number of electricity hedges in the period covered by this filing. Therefore, my focus was appropriately on the gas hedges the Company executed. As set forth in my direct testimony, a substantial portion of the Company's hedges should be disallowed.

The Company claims the Transition Adjustment Mechanism ("TAM") Guidelines prevent them and other parties from making or advocating reasonable changes to the

TAM procedures. Any agreement or procedure should be re-evaluated or be flexible enough to include the logical consequence of any dramatic change. I strongly believe that the Company (and the Commission) cannot ignore the additional fixed revenue recovery resulting from a dramatic increase in the projected sales level used for ratemaking purposes from just one year ago. As PacifiCorp has virtually no direct access load, the TAM is essentially a power cost adjustment mechanism applied to bundled customers. The power cost adjustment mechanisms of Puget Sound Energy ("PSE") and Avista Utilities ("Avista") in Washington both take into account or recognize the impact on fixed cost recovery from increases or decreases in sales levels. The PacifiCorp TAM mechanism needs to do this as well.

Q. ARE YOU RESPONDING TO PACIFICORP'S OTHER ARGUMENTS?

A. No. I continue to support my direct testimony on the source of the forward price curve, sales activity on the ISO and the DC Intertie, and Bear River hydro normalization. PacifiCorp agreed to my Bear River adjustment and did not raise any new facts that warrant a response on my other contested issues. The Commission should resolve these issues as explained in my direct testimony.

GADSBY UNITS 4-6

Q. WHAT IS THE COMPANY'S RESPONSE TO THE ICNU RECOMMENDATION TO REMOVE THE MUST RUN DESIGNATION IN THE GRID MODEL FOR GADSBY UNITS 4-6?

A. The Company opposes the ICNU recommendation. PPL/105, Duvall/31, lines 3-18. The Company continues to argue for a must run designation in its GRID modeling and claims the projected capacity factor of these plants by the GRID model (32%) is comparable to the capacity factor for these units in 2009 (33%). Id.

Q. WHAT IS YOUR RESPONSE?

A. The Company's weak response is unpersuasive for two reasons. First, with a must run designation, each of the three Gadsby units will run each and every hour in the GRID simulation, except when there is a scheduled maintenance outage. The fact that this modeling convention results in about the same annual energy output amount as compared to 2009 ignores the manner in which the energy was actually dispatched from these plants in 2009. Confidential Exhibit ICNU/107 shows that **[Confidential]** [redacted] **[Confidential]**.

Second, and more important, past results or operations should not be used in isolation to defend the results of a GRID simulation. The purpose behind doing a forward looking projection of PacifiCorp's resource dispatch is to simulate expected operations for 2012. This objective is quite different from the goal of simply duplicating a past year such as 2009. For example, in response to ICNU data request ("DR") 13.13, the Company provided the most recent twelve months of hourly generation levels of the Gadsby units (July 1, 2010 to June 30, 2011). As shown by the following summary table, this data response shows the units are not run as must run, and there continues to be a substantial number of hours in each month when the units are off line.

[Confidential]

Gadsby Units - Hours of Non-Operation

Month	Unit 4	Unit 5	Unit 6
July 2010	[redacted]	[redacted]	[redacted]
August	[redacted]	[redacted]	[redacted]
September	[redacted]	[redacted]	[redacted]
October	[redacted]	[redacted]	[redacted]
November	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]
Jan 2011	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]
March	[redacted]	[redacted]	[redacted]
April	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]
June	[redacted]	[redacted]	[redacted]
Total:	[redacted]	[redacted]	[redacted]
Percent of Time:	[redacted]	[redacted]	[redacted]
Average Hours:	[redacted]	[redacted]	[redacted]
Capacity Factor:	[redacted]	[redacted]	[redacted]

[Confidential] As shown by the table, the actual capacity factor for these twelve months is **[Confidential]** [redacted] **[Confidential]** a value consistent with the GRID capacity factor for these units when the must run designation is removed in the GRID simulation **[Confidential]** [redacted] **[Confidential]**.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH REGARD TO THE GADSBY MODELLING DESIGNATION?

A. As I have stated in my prior testimony filed in this proceeding, the must run designation should be removed from the Gadsby units in the net power cost simulation. This is a very straightforward issue. As these units are not operated as must run in the real world, they should not be designated as must run in the GRID simulation.

SALES MARKET CAPS

Q. WHAT IS THE COMPANY'S RESPONSE TO THE ICNU RECOMMENDATION TO REMOVE THE SALES MARKET CAPS?

A. The Company opposes the recommendation, stating that market depth should be measured by its average sales level as experienced in the last four years, the ICNU adjustment would double count trading transactions, and no new information has been provided to the Commission regarding this issue. PPL/105, Duvall/16-20. I disagree.

Q. WHAT IS YOUR RESPONSE TO COMPANY'S ASSERTION THAT THE MARKET CAPS SHOULD BE BASED ON PACIFICORP'S AVERAGE SALES IN THESE MARKETS?

A. As I noted in my direct testimony, there is no economic justification for imposing a market sales cap. Moreover, the workpapers provided by the Company with regard to the former "graveyard" cap method illustrates the absurdity of the Company average sales method approach to deriving the sales caps. Confidential Exhibit ICNU/111 is a comparison of the Company's average energy calculation for each trading hub for this limited time period and the maximum hourly transaction for each month. As the Company does not enter into a transaction during every graveyard hour in the month (about 150 hours per month – 5 hours per day times 30 days), the Company's derived average energy value is significantly lower than the actual transactions the Company executed during these hours. To illustrate the Company's method, consider the graveyard transactions for the month of January 2006 at the **[Confidential]** [redacted]

[redacted] **[Confidential]**. The first two pages of Confidential Exhibit ICNU/111 compare the Company's derived average value using all hours to the maximum hourly sales amount the Company transacted for each month. The third page of the exhibit shows the resulting PacifiCorp graveyard caps based on the average value from the four corresponding months to the average of the four years' maximum value. The Company derived values shown on the third page of this exhibit are used in the GRID simulation to cap sales activity by month at each hub. This exhibit illustrates how the Company's method grossly understates the level of the transactions it has done every month at each of the trading hubs.

While the Company argues its ability is limited by the average energy it has sold over all hours (including hours where no transactions were executed), a far more meaningful cap value would be based on the actual maximum value it has transacted at each hub. Diluting these values by averaging in hours where no transactions occurred simply restricts the sales amount below the levels the Company has achieved as it ignores the size of the actual transactions the Company has done at each hub. This same mathematical technique is used by the Company to derive its heavy load hour and light load hour caps in this proceeding. The Company's method is inappropriate as it results in cap values that are substantially lower than the actual transactions it has executed at each trading hub. The Company's approach restricts sales when the Company has marketable surplus capacity available to sell. This sales cap restriction is not employed by other

Pacific Northwest utilities including Portland General Electric, PSE or Avista. It should not be employed in the Company's GRID simulation either.

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE COMPANY'S DOUBLE COUNTING ARGUMENT.

A. The Company asserts removing the caps will result in increased trading transactions which are accounted for through the Company's trading margin adjustment. The purpose of the trading margin adjustment is to identify those transactions where there was a simultaneous purchase and sale. According to the Company, there would be a double counting of sales between the additional GRID market transactions and the trading transactions.

Q. DO YOU AGREE?

A. No. Removal of the inappropriate sales caps increases the sales transactions by a relatively modest amount which is far less than the historical sales transactions. The average of the four years Company's sales for deriving the caps average roughly 27 million MWhs. The Company's arbitrage/trading adjustment is based on an average of about 4 million MWhs. Under the Company's sales caps, the GRID model has 8 million MWhs of sales while the elimination of the caps increases sales by 1 million MWhs to produce a total of 9 million MWhs of sales. While I recognize the fact that the bilateral transactions are occurring over many months, the discrepancy or gap between historical sales results (27 million MWhs) and the Company GRID sales and trading adjustment (8 + 4 = 12 million MWhs) in this proceeding is far too great (15 million MWhs). Given this very large gap, I do not believe there would be a double counting of sales activity with the elimination of the market sales caps.

Q. WHAT IS YOUR RESPONSE WITH REGARD TO THE COMPANY'S ASSERTION THAT NO NEW EVIDENCE HAS BEEN PROVIDED TO THE COMMISSION ON THIS MATTER?

A. I obviously disagree. Confidential Exhibit ICNU 105, Schoenbeck/8 was compiled specifically to show that the electricity trading markets are much large than simply PacifiCorp's transactions. In my view, this is recognized by PacifiCorp as the Company does not impose *purchasing* caps in its GRID simulation. Imposing the Company's sales caps at major sales hubs cannot be justified on economic or historical grounds. The Commission should adopt the ICNU recommendation and eliminate the sales caps from the GRID net power cost simulation.

<u>HEDGING</u>

Q. HAVE YOU REVIEWED THE COMPANY'S REBUTTAL TESTIMONY ADDRESSING THE ICNU HEDGING DISALLOWANCE?

A. Yes. The Company's testimony addresses their current hedging strategy as well as raising several criticisms with the ICNU recommendation. These criticisms assert ICNU performed no review of the Company's electricity hedges, the ICNU recommendation is based upon an after the fact review, and the ICNU recommendation ignores the fact that in prior years the Company's hedging program has provided substantial benefits to Oregon customers.

Q. ARE YOU DISPUTING OR DISAGREEING WITH THE COMPANY'S CURRENT HEDGING STRATEGY?

A. I have not performed a thorough analysis of the Company's current hedging strategy and its execution at this time. My recommendation is based on the hedging strategy that was in place at the time certain transactions were executed in 2007 and 2008. For this period, as noted in Exhibit PPL/400, Bird/8, the effective hedging policy was dated November

2006. The 2006 Policy and its execution is at issue in this proceeding—not the Company's current hedging policy. Any testimony addressing the Company's current hedging strategy is irrelevant with regard to the ICNU recommendation in this proceeding.

Q. DID YOU JUST REVIEW THE GAS HEDGES THE COMPANY EXECUTED FOR 2012?

A. No. In a response to a Company data request, I noted I had reviewed the Company's electricity hedges. Unlike the gas transactions, this review revealed the Company had not executed a single electricity transaction during 2007 and the first transaction executed in 2008 occurred at the very end of May for a second quarter sale. As the ICNU disallowance recommendation is based on executing too many transactions too soon, I did not believe these conditions were present with regard to the Company's electricity hedges. The low level of electricity hedging activity can be seen by reviewing Exhibit PPL/108, Duvall/1. This exhibit summarizes the Company's hedging activity for the five most recent Oregon dockets including the instant proceeding. Note that the quantity of short term firm electricity sales shown in the first row of this exhibit for UE 227 is far below the ultimate values included in rates in all the other dockets. Even comparing the instant volumes with UE 216 shows the Company has executed only about 36% of the sales volumes as compared to the last proceeding. Similarly with regard to the electricity financial swaps shown in the row entitled "Net Electric Swaps Expenses" the activity for this docket is not close to the proceeding dockets. However, this is not the case with regard to the natural gas swap expense shown on this exhibit. For gas swaps, the UE 227 value is similar to the net expense indicated for dockets UE 216, UE 207 and UE 199.

Consequently, when the total hedging expense is combined, the lack of electricity sales (either physical or financial) in this docket causes there to be a substantial cost due to its gas hedging that the Company is proposing to include in rates. For all practical purposes, the UE 227 hedging expense wipes out all the net hedging benefits calculated by the Company for the prior four dockets.

Q. IS YOUR RECOMMENDATION BASED UPON AN AFTER THE FACT ANALYSIS OF THE COMPANY'S HEDGES IN THIS PROCEEDING?

A. Absolutely not. The standard for determining whether or not a decision was reasonable should be dependent upon what was known at the time the decision was made. This is the standard I applied in formulating my recommendation. In my view, entering into transactions that have delivery periods beyond 48 months, or if too many transactions are executed too far in advance, it is imprudent. In fact, while the 2006 Policy would allow for such transactions ("non-standard" transactions), they required additional approval. ICNU sought any documentation from the Company to support the execution of these non-standard transactions in ICNU DR 13.14. Exhibit ICNU/112, Schoenbeck/1. The Company stated "there are no documents or analyses responsive to this request" and referenced Exhibit PPL/400, Bird/9, lines 4-15 "for an explanation of the Company's decision-making." Id. This cited portion of testimony is the Company's response to the ICNU criticism for hedging "too far" in advance and the subsequent section of testimony addresses the "too many" hedges issue. The Company claimed the "too far" issue was to capture ratepayer savings, but it has no proof or documents to support this assertion. Regarding the "too many" issue, the Company is asserting third party experts were projecting even higher gas costs and, therefore, it was prudent to execute the transactions.

However, this approach is contrary to the notion that you cannot beat the market—a notion with which the Company appears to agree. PPL/400, Bird/16, lines 21-22.

By executing all these transactions, the Company had hedged **[Confidential]** [redacted] **[Confidential]** of its 2012 gas requirements by **[Confidential]** [redacted] **[Confidential]**. With no documentation to support these transactions, ICNU continues to advocate the selected volumes should be disallowed by the Commission.

Q. SHOULD THE FACT THAT PRIOR HEDGING BENEFITS WERE INCLUDED IN RATES BE CONSIDERED IN THE COMMISSION'S DECISION MAKING PROCESS ON THIS ISSUE?

A. No, I do not believe so. The issue should be decided on the circumstances that were or were not considered at the time the transactions were executed. Past or even possible future hedging benefits or costs should not be considered. However, if the Commission decides to consider the past benefits the Company is alleging as summarized on Exhibit PPL/108, the $118 million value is a system benefit. For Oregon, the amount would be about $30 million for an average of $7.5 million per year. This amount would equate to about a 0.7% Oregon rate benefit or $12.60 per customer for each of the last four years. In this docket, the per-customer hedging cost the Company is proposing to include in rate charges is $42.86. Combining the projected hedging loss from this docket with the prior gains nets to a system benefit of just $17.8 million. This equates to just $4.4 million for Oregon or an average of just $0.9 million per year. This is a rate benefit of just 0.08% or about $1.50 per customer per year, a very low amount. In addition, the Company's claimed benefits are based on its actual hedging policy. PacifiCorp has not provided an estimate of what the benefits would be if it had executed hedging contracts under a more appropriate hedging policy.

LOAD FORECAST/TAM GUIDELINES

Q. HOW DID THE COMPANY RESPOND TO THE ICNU RECOMMENDATION TO TAKE INTO ACCOUNT THE ADDITIONAL FIXED REVENUE ATTRIBUTABLE TO INCREASED SALES LEVELS?

A. The Company opposes the recognition of the additional fixed revenue, stating it is outside the scope of the TAM proceeding and agreed upon guidelines. PPL/600, Griffith/2-6.

Q. WHAT IS YOUR RESPONSE?

A. The Company is in essence asking all parties—and the Commission—to ignore relevant and extraordinary circumstances. It was less than one year ago that the Company had an 8% rate increase for Oregon ratepayers in part predicated on a low level of retail sales. Now, in this instant TAM docket, the Company is seeking a 5.4% increase in overall rate charges due in large part to an increase in Oregon and system-wide retail loads. The Company states the increase is driven from a quicker economic recovery than had been anticipated. In my view it is inappropriate to increase the per unit variable cost recovery without recognizing the affect on the per unit fixed cost recovery from the substantial load increase. As PacifiCorp has virtually no direct access load, the TAM mechanism is essentially a power cost adjustment for PacifiCorp without a true-up or deviation cost sharing between ratepayers and shareholders.

Q. ARE YOU AWARE OF OTHER JURISDICTIONS THAT TAKE INTO ACCOUNT FIXED COSTS IN POWER COST ADJUSTMENT MECHANISMS?

A. Yes. In the state of Washington, both PSE and Avista have fuel and purchase power cost mechanisms that take into account fixed cost contribution in some manner. In the case of

PSE, there is a proceeding equivalent to a "TAM only" proceeding in Oregon. It is referred to as a power cost only rate case ("PCORC"). In this proceeding, the allowable per unit cost is derived including certain production and transmission fixed cost components. Consequently, increases or decreases in load levels outside a full general rate case will increase or decrease the fixed cost per unit charges recovered in rates. In the case of Avista, the power cost mechanism includes a revenue credit (or debit) to the extent loads differ from the level used to establish rates in the general rate case. This revenue credit is based on the total production and transmission related revenue requirement allowed in rates. Mechanisms such as these allow for a more even handed recognition on how changes in retail load levels affect more than just the variable power costs of a utility. In this instant proceeding, when PacifiCorp is alleging a substantial increase in its load growth, the Commission should consider other possible offsetting revenue streams to mitigate yet another substantial rate increase to Oregon ratepayers. One such approach is to recognize the substantial additional fixed revenue, as I recommended in my direct testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.