BEFORE THE UTAH PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	))))))	DPU EXHIBIT 3.0 DOCKET NO. 10-035-124 TEST PERIOD

Pre-filed Direct Testimony

Of

Douglas D. Wheelwright

On Behalf of

Utah Division of Public Utilities

March 9, 2011

Q: **Please state your name, business address and title.**

A: My name is Douglas D. Wheelwright. I am a Utility Analyst in the Division of Public Utilities (Division). My business address is 160 East 300 South, Salt Lake City, Utah 84114.

Q: **On whose behalf are you testifying?**

A: I am testifying on the Division's behalf.

Q: **Please describe your position and duties with the Division**.

A: I research, analyze, document, and establish regulatory positions on a variety of regulatory matters. I review operations reports and evaluate compliance with the laws and regulations. I provide testimony in hearings before the Utah Public Service Commission ("Commission"); and assist in the analysis of testimony and case preparation.

Q: **Does the Division have any general observations concerning the forecast Net Power Cost?**

A: Yes. The Division has compared the projected net power cost to historical results provided by the Company. Actual monthly results have been used in order to compare historical June year end information to the projected June year end for the test period. While several of the individual line items appear to be in line with the historical trends, there are a few expenditures or revenues which raise general concerns because those expenditures or revenues do not appear to be in line with historical trends and are not explained in the testimony.

Q: **Can you identify the specific accounts that appear to be outside the normal projections that have not been explained?**

A: DPU exhibit 3.1 is the June year end historical net power cost information for 2005 through 2010. This information has been compared to the forecast provided by the Company for both 2011 and the 2012 test period. The line items that have the greatest variation from the historical information are Short Term and Secondary Sales (Balancing Sales), Qualifying Facilities Purchases, Short Term Purchases and Balancing Purchases. A review of prior rate case information indicates that the forecasts for these categories have been significantly different than the actual amounts. While the areas identified are a concern and require further examination, these issues could be resolved with adjustments.

Q: Can you provide some specific examples of these items and the comparison to the actual results?

A: Yes. Comparing the June 2010 actual results in the variance report to the forecast provided in the last general rate case, Docket No. 09-035-23, Short Term Sales were forecast at $654 million compared to the actual sales of $352 million for a difference of $302 million. Comparing the June 2009 actual results to the forecast, short-term sales were forecast at $994 million compared to the actual sales of $615 million for a difference of $379 million.

Short-term firm purchases for June 2010 were forecast at $-24 million compared to the actual results of $-161 million or a difference of $-137 million. Short-term firm purchases are showing up as a negative purchase amount due to the inclusion of the mark to market value adjustment of electric swap transactions. The value of these contracts will fluctuate as the forward price curve changes. Short-term firm purchases for June 2009 were forecast at $470 million compared to the actual result of $6 million for a difference of $464 million.

Total secondary and balancing sales were not forecast in the previous rate case and totaled $2 million for 2009 and $1 million for 2010. The forecast for the 2012 test year calls for $338 million in secondary and balancing sales. The Company has indicated that short-term and secondary (balancing) sales should be reviewed together, however, this still represents a significant increase and variance from the historical results.

Q: Have you noticed a trend in the sales and purchases in recent years?

A: Yes. There is a correlation between the Short Term Sales and Short Term Purchases identified in the historical results. Chart 1 below is a review of the short-term firm and balancing sales compared to short-term firm and balancing purchases. Information for 2005 through 2010 are historical results while 2011 and 2012 are forecast amounts. A linear trend line has been included for the actual sales and purchases which can be compared to the forecast amounts. There appears to be a strong correlation between these two categories and a downward trend from the peak in 2007.

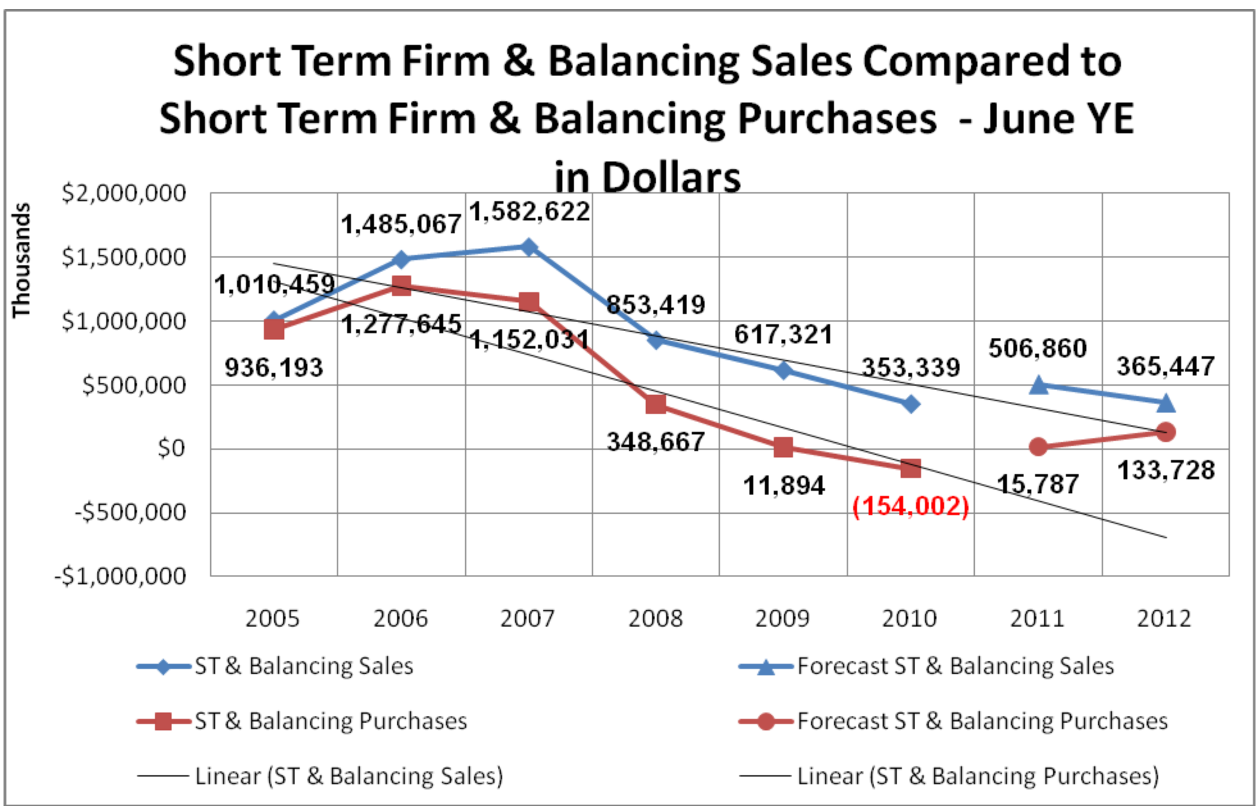

CHART 1

The 2011 forecast for short term and balancing sales indicates a $154 million increase which does not follow the downward trend of the last three years. The increase in short term and balancing purchases is driven by the reduced value of the electric swaps that are included in this category. The impact of the lower sales and change in electric swaps will be discussed later.

Q. Have you noticed a similar trend in long-term sales and purchases?

A: Yes. Chart 2 below is a review of the long-term sales compared to long-term purchases. Historical results are used for 2005 through 2010, while 2011 and 2012 are forecast amounts. A linear trend line has been included for the actual sales and purchases. There appears to be a similar correlation between these two categories and a downward trend from the peak in 2007.

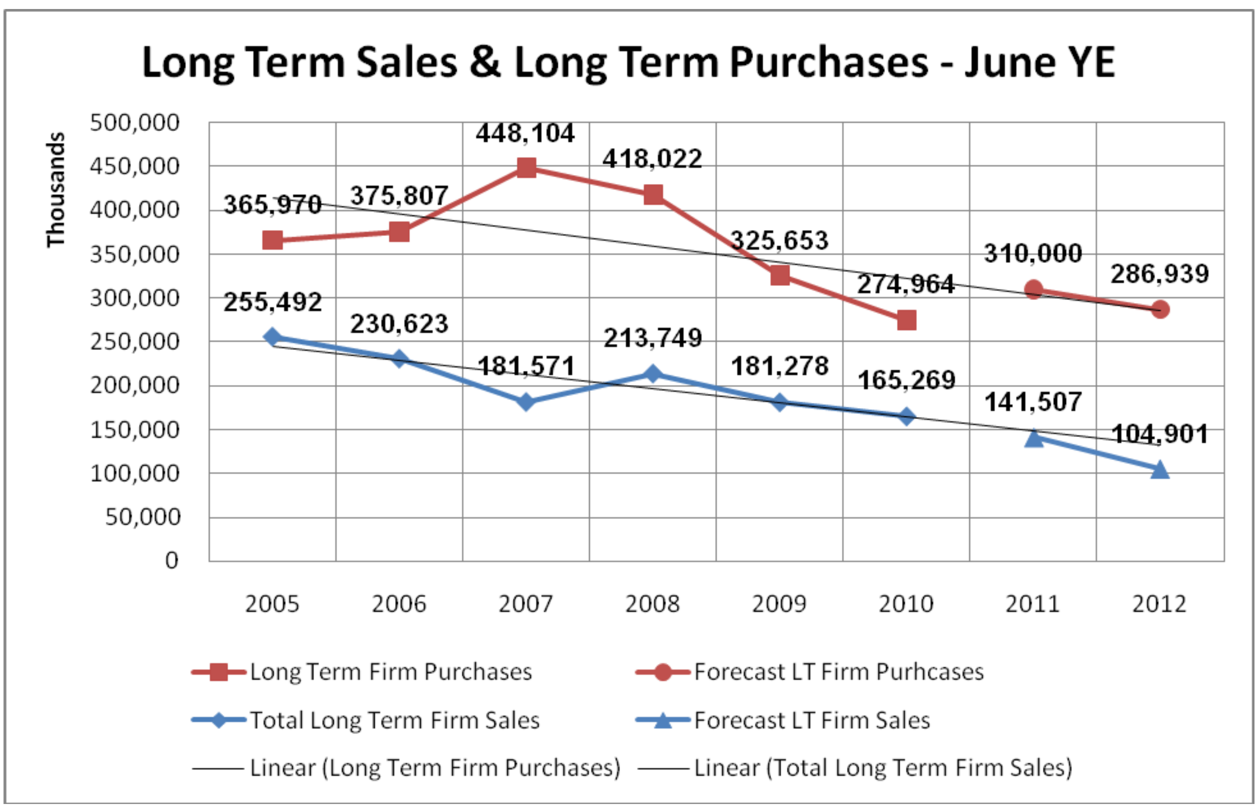

CHART 2

Similar to the short sales above, the 2011 forecast for long term sales indicates a $35 million increase which does not follow the downward trend of the last three years. Long term purchases appear to be roughly consistent with the historical trend.

Q: Why do you think this downward trend is important?

A: One of the reasons for the significant increase in the forecast for net power cost is the change in the forecast value of the electric swaps transactions included in the short term firm purchases. If we compare the historical information to the forecast, for the period ending June 2010, short term purchases were $-161 million. (See DPU exhibit 3.1) This negative amount reduced total net power cost and was $136 million higher than the amount forecast in Docket No. 09-035-23.[1] In previous testimony the Company has indicated that the value of the physical electric contracts and electric swaps has offset the changing value of the natural gas swaps and created a price fluctuation hedge. With a continued reduction in the physical electric sales, the value of the electric physical and electric swap contracts may not be able to offset the price of the natural gas swaps. This change in the Company position will put upward pressure on net power cost. This can be seen in the forecast provided in this case. For the June 2011 period, gas swaps add $139 million to the gas burn expense while electric swaps provide a credit of $223 million.[2] These transactions reduce NPC by $84 million for 2011. In contrast, for the test period ending June 2012, gas swaps add $161 million to the gas burn expense while electric swaps provide a credit of $62 million. The combination of these transactions increased NPC by $99 million for the test period.[3] A continued reduction in sales will reduce the opportunity for physical contracts to offset the additional costs.

Q: How does the historical information compare to the actual MWh projection?

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[1] PacifiCorp, June 2010 Variance report
[2] _UT GRC June 2011 (GOLD)_2010 12 27
[3] _UT GRC June 2012 (GOLD)_2010 12 23

A: Chart 3 below is a comparison of the total requirements including both system load and sales in MWh. A trend line has been included to indicate the direction of the sales compared to the projections. While the net system load forecast remains close to the historical values, the Company is projecting an increase in sales for 2011 and 2012 which is significantly higher than the previous three years and which appears to explain the increase in forecasted total requirements) .

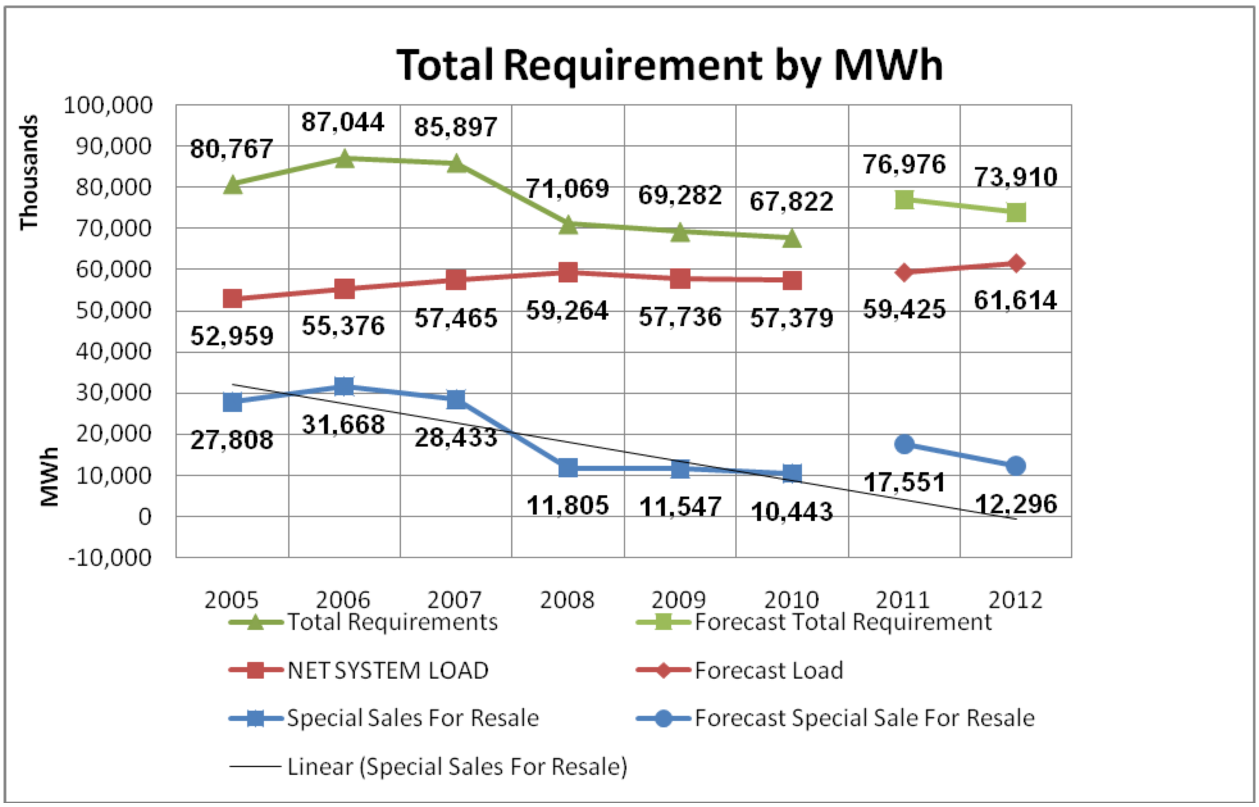

CHART 3

Q: What have you determined about the load forecast?

A: The last two lines of Exhibit 3.1 & 3.2 identify the historical load and percentage change along with the projected change for the test period. Exhibit 3.1 represents the annual percentage change using a June year-end. Exhibit 3.2 represents the same information in six month periods. The percentage increase represents the increase over the same time period of the previous year. For example the 6.2% increase identified for January through June 2011 is the increase from the actual amount reported for January through June 2010. The increase in this period appears to be an unusually large compared to the other periods under review. On an annual basis, however, the increase for 2011 is 3.57% with an additional 3.68% increase projected for the June 2012 test period. This projected increase is comparable to the load growth experienced by the Company in the 2006 through 2008 time period.

Q: Do you have additional information specific to the last six months (January through June 2012) identified in the Company's proposed test period?

A: Yes. DPU Exhibit 3.2 is a review and comparison of the actual July 2008 through June 2010 net power cost results compared to the forecast July 2010 through June 2012. This analysis compares the previous two years of actual results to the forecast but is broken into six month time periods. Significant changes were noted in the forecast for total storage and exchange, qualified facilities purchases, electric swaps and system balancing purchases. It should also be noted that historical information on electric swaps, gas swaps and the wind integration charges are not provided (i.e., not called out) by the Company in the actual results. The items that appear to have variation from the historical information have been color coded in yellow in Exhibit 3.2. Items that appear to be a concern in the last six months of the test period have been color coded in orange. While the areas identified are a concern and require further examination, these issues could be resolved with adjustments.

Q: Are there other differences in the last 6 months of the Company's test period?

A: The Company has not included some of the QF contracts for the last six months of the test period. The contracts that have been excluded mature December 2011 and historically have been renewed on an annual basis. The exact amount of these contracts may not be known at this time but it is unlikely that these contracts will not be renewed and amounts should be included at either historic levels or valued based on the forward price curve. Chart 4 is a review of the historical and projected cost for the QF contracts.

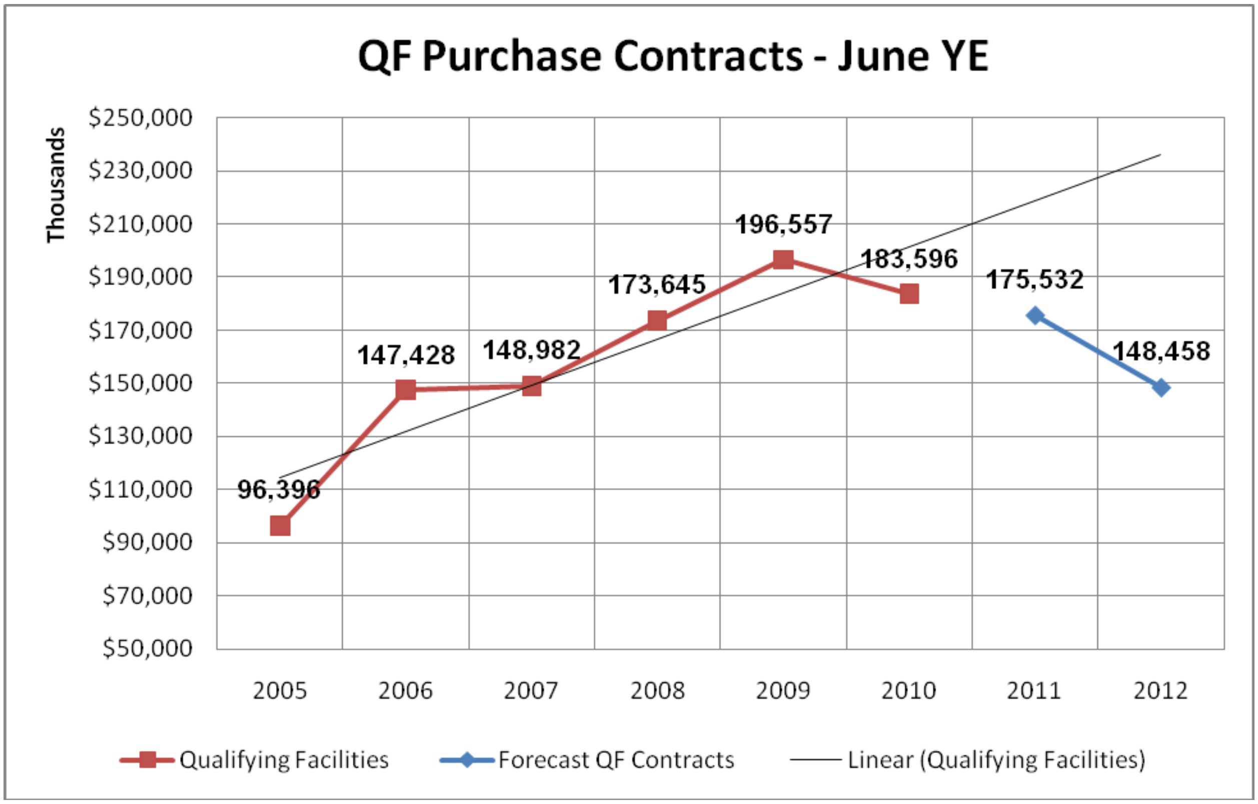

CHART 4

As can be seen in Chart 4, the Company's forecast of the QF contracts is noticeably different from the trend. Including the QF contracts that can reasonably be assumed to be renewed would bring the forecast more in line with the historical trend.

Q: **Have you prepared information to identify the difference in net power cost between the forecast test period ending June 2012 compared to using the calendar year ending December 2011?**

A: Yes. Exhibit 3.3 identifies the line items included in power cost for both the proposed test year and for the calendar year ending December 2011 and is based on the monthly information provided by the Company. The change in net power cost between these two periods is a reduction in net power cost of $124 million from $1.521 billion to $1.397 billion. Significant changes were noted with a $76 million difference in electric swaps, a $10.5 million reduction in the total coal fuel burn expense, and a $40.2 million reduction in the total gas fuel burn expense. The Division notes that these changes are based on the Company's filing, which does not provide an optimized GRID run to determine the net power costs for a 2011 calendar year test period. Nevertheless, these changes should be reasonably close for the purposes herein. Exhibit 3.2 & 3.3 summarize the change in net power cost between the proposed June 2012 test period and year end December 2011.

Q: Do you have any recommendations concerning net power cost and the proposed test year ending June 2012 vs a calendar year test period ending December 2011?

A: The Company provided information for the test year ending June 2012 which includes the forecast for net power cost on a monthly basis. When the forecast has been compared to the historical results there are items of variation that will need further review and explanation. While there are items of concern in the last six months of the proposed test period, it is likely that any of these items can be handled with regular adjustments. The Division staff will continue to review this information as part of this general rate case. In addition, the Division has hired an outside consultant to review the net power cost in this Docket.

Q: Does this conclude your testimony?

A: Yes.