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 11.0 SR-RR DOCKET NO. 10-035-124 NET POWER COST - HEDGING

Pre-filed Surrebuttal Testimony

of

Douglas D. Wheelwright

on Behalf of

Utah Division of Public Utilities

July 19, 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: Are you the same Douglas Wheelwright that filed direct testimony for the Division in this matter?

A: Yes.

Q: What is the purpose of your surrebuttal testimony in this matter?

A: I will respond to several issues raised in rebuttal testimony and will discuss other issues that have been addressed by other parties in this case. I do not comment on all of the ideas and statements made by the various witnesses. Silence on a given subject does not imply that the Division necessarily agrees with the witness on that subject.

Q: Please identify PacifiCorp witness's testimonies that you wish to respond to.

A: I will respond to issues addressed in the rebuttal testimony of Mr. Frank C. Graves, Stefan A. Bird and John A. Apperson.

Q: How do you respond to the Company's comments from Mr. Frank C. Graves?

A: I agree with several of the points and the concluding recommendations of Mr. Graves. He suggests that the focus should be on risk-limiting goals that are appropriate for ratepayers and that these goals should be monitored in a transparent fashion. Specific recommendations include obtaining input from regulators and customers concerning the goals of the hedging program and the risk simulation model to be used. A formalized plan would include the type, timing and triggers for implementing a hedging strategy.

The program would require a review of the hedging goals and strategy when there is a major change in market conditions and provide quarterly or semi-annual reporting of the success in adherence to the agreed plan. All of these items are closely aligned with the recommendations made by the Division in Docket No. 09-035-23. In that case, the Division recommended the following:

> The Commission should seek input from interested parties and then provide guidance and standards for the Company hedging strategy. This guidance would not need to contain rigid goals or strategies but should include the following: (1) the objective of hedging, (2) the cost of hedging, (3) the mix of hedging tools allowed, (4) the time horizon for financial derivatives, (5) the appropriate criteria or triggers for discretionary hedging, and (6) the appropriate reporting requirements. Guidelines would need to be reviewed every 3 – 5 years or if there were significant changes in market conditions. Commission approval of such plans would serve to protect the Company from retrospective "second-guessing," so long as the approved plan was followed. Allowance should be made, however, for approving deviations from such a plan when extraordinary conditions warrant. [1]

Q: How did the Company respond to the Division's recommendations made in the previous case?

A: In rebuttal testimony, Mr. Gregory N. Duvall stated:

> While the Company believes these are important issues, it would be more appropriate to address them in the context of the currently active Energy Cost Adjustment Mechanism ("ECAM") or Natural Gas Hedging dockets. The Division's proposal raises a number of questions such as what it means for the Commission to "approve" the Company's hedging portfolio plan. The degree of Commission oversight would vary depending on whether there is an ECAM and if so, what form it takes. The Company believes the Division's recommendations cannot get the full consideration they deserve until the Commission has ruled on the structure of an ECAM for Rocky Mountain Power.[2]

It appears that this issue keeps moving from docket to docket without being addressed or resolved. In the ECAM order[3], the Commission stated that a general rate case is the appropriate setting to review this issue.

Q: Are there items in Mr. Graves testimony that you disagree with?

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[1] Docket No. 09-035-23, Direct Revenue Requirement Testimony of Douglas D. Wheelwright, p. 16.
[2] Docket No. 09-035-23, Rebuttal Testimony of Gregory N. Duvall, p. 46.
[3] Docket No. 09-035-15, Report and Order - Rocky Mountain Power Energy Balancing Account, p. 72.

A: Yes. I believe he has misrepresented the concern of the Division and other parties that RMP has not responded to the changing market conditions. He states that parties believe that the Company should have "foreseen" the reduction in natural gas prices that ensued from the shale gas production.[4] The Division has not suggested that these events could have been predicted with absolute precision. What the Division and parties have suggested is that given the substantial amount of money that was committing to hedging, the Company should have been more aware of the potential impact that developments such as shale gas would have on future prices.

The Company has acknowledged that market conditions for natural gas have experienced a dramatic change in the past 3 years. The changing natural gas market has caused regulators across the country to review the policies for other utilities as was outlined by Division witness Mark Crisp.[5] Market conditions have prompted published articles discussing the effectiveness of hedging programs.[6] While the changing market conditions may have been unforeseen, they should have prompted the Company to review the hedging program as recommended in Mr. Graves' rebuttal testimony.[7] The Division is certainly not suggesting that the Company should have speculated on future gas prices, only that the Company's current hedging program has not been flexible enough and does not allow it to react even as market events were unfolding around them.

Q: How do you respond to the comparison to Portland General's hedging practice and the example of the long-term Hermiston contract?

A: The testimony references the 2009 IRP for Portland General. The IRP document states:

> PGE layers in contracts of differing durations of up to five years in advance for a portion of the expected future fueling requirements. As we get closer to our fueling need, purchases are increased to ensure that we have acquired contracts to meet our expected requirements roughly one year in advance.[8]

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[4] Rebuttal Testimony of Frank C. Graves, p. 3, line 45.
[5] Pre-filed Direct Testimony of Mark W. Crisp, May 26, 2011.
[6] NRRI, Natural Gas Hedging: Should Utilities and Regulators Change Their Approach, Ken Costello, May 2011.
SNL Financial, The merits of hedging in a low-price environment, Jodi Shafto, June 22, 2011.
SNL Financial, Dodd-Frank's capital rules could 'punish' end users, Peter Marrin, July 8, 2011.
[7] Rebuttal Testimony of Frank C. Graves, p. 27, line 496.
[8] PGE 2009 Integrated Resource Plan, Chapter 7, p. 144.

While Portland General does allow purchases up to five years in advance, it is unclear what percentage of the future requirements are being purchased in the forward years. The guidelines for PacifiCorp are as follows:

> [redacted][9]

[redacted]

It is interesting that the Company has used the Hermiston contract as an example of long-term hedging. While this has been a favorable contract for rate payers, it has been identified as a maturing contract and one of the reasons for the projected increase in natural gas costs. The maturity of this favorable contract should be another triggering event that should prompt a review of the current hedging strategy and a possible report to regulators.

Q: Do you agree with Mr. Graves that the evaluation of the hedging program should be reviewed not as winning and losing but should be evaluated based on whether the strategy has stayed within the expected range?

A: In general, yes. However, year-over-year losses should raise some concerns not only on the part of regulators but the Company, acting in the public interest, should be concerned. With that said, there are many ways to evaluate a hedging program. One of the primary concerns of the Division is that the current program does not have standards or guidelines in place that have been reviewed or approved by the Commission. There is no established or predetermined way to evaluate the success or shortcoming of the current program other than comparisons to other utilities. Parties have come up with several different methods to evaluate the performance of the total hedging program and a review of the swap transactions. In DPU data request 20.9, the Division asked for specific information concerning how the stop loss limit was determined and if it had been changed. The Company indicated that this information is commercially sensitive and

[9] PacifiCorp, Exhibit 10 – Commodity Price Exposure Hedge Program, p. 2, Item 7.

highly confidential and could only be viewed on site but indicated that it had not been changed since 2006. It is difficult to determine the success of a program if the guidelines are not known and regularly reviewed and reported.

Q: How do you respond to the testimony of John A. Apperson and his allegation that excluding the physical contracts provides an incomplete analysis of the hedging program?

A: The focus of my analysis was on the natural gas and electric swaps since the EBA docket ordered that this portion of the hedging program be excluded from the base and actual NPC.[10] The EBA order indicates that the inclusion of any swap costs must be decided in a general rate case.

Q: Mr. Apperson is critical of your analysis in table 2 and feels that the total hedging cost should be compared to the total net power cost of $1.5 billion. Do you agree with this different calculation method?

A: That is another way to look at these costs but I believe calculating the hedging cost compared to the total NPC dilutes the significance of the Company's hedging activities. However, using Mr. Apperson's calculations, the total hedging cost adds 6%, or $90.7 million, to the total NPC. This represents a significant addition to the total NPC and should be carefully reviewed and examined by the Commission to determine if they are appropriate to be included in rates.

The natural gas swaps portion of the total hedging strategy is directly related to the natural gas fuel cost and should be reviewed and included in the total gas fuel expense. The total of the natural gas fuel and natural gas swap costs should be added together to determine the total cost per MMBtu for gas fired electric generation. The total cost per MMBtu including swaps has not been addressed by the Company. Based on the revisions included in the UT GRC 2011 Rebuttal Gold NPC Study grid run, the total gas fuel burn expense has been reduced along with a reduction in the projected MMBtu for the gas facilities. Table 1 below is a comparison of the cost per MMBtu in the original forecast compared to the information provided in the rebuttal NPC study.

[10] Docket No. 09-035-15, Report and Order - Rocky Mountain Power Energy Balancing Account, p. 75.

Table 1

	UT GRC June 2012 (GOLD) 2010-12-23	Cost per MMBtu	UT GRC 2011 Rebuttal Gold NPC Study 2011-06-22	Cost per MMBtu
Gas Fuel Burn	$328,543,939	$ 4.85	$301,115,635	$ 4.94
Gas Physical	$69,552	$ 0.00	$(134,839)	$ (0.00)
Gas Swaps	$160,723,241	$ 2.38	$155,955,188	$ 2.56
Gas Fuel Burn Expense	$489,336,732	$ 7.23	$456,935,984	$ 7.49
Pipeline Reservation Fees	$26,451,016	$ 0.39	$26,483,817	$ 0.43
TOTAL GAS FUEL BURN EXPENSE	$515,787,748	$ 7.62	$483,419,801	$ 7.93
Natural Gas Volume (MMBtu)	67,672,662		60,997,565	
Total Net Power Cost	$1,521,262,900		$1,508,445,770	
System Load (MWh)	61,614,191		61,611,123	

While the natural gas fuel expense and volume has gone down, the cost associated with gas swaps have come down only slightly. This reduction in the projected volume results in an increase in total cost per MMBtu for the natural gas generation from $7.62 to $7.93. Referring back to the EIA long-range forecast, the spot price for natural gas will not be in the $7 range until 2035.

The revised forecast provided in rebuttal testimony calculates as a 9.9% reduction in the projected natural gas volume. This downward revision in the projected need for natural gas supports the recommendation from the Division and other parties to hedge less than 100% of the forecast requirement. A modification to the current strategy would allow for quantity fluctuations due to changing demand or economic conditions.

Q: Do other utilities review the fuel cost including the hedging cost?

A: Regulators in South Carolina recently completed their annual audit of the fuel costs for Progress Energy.[11] This report identified the Company's total fuel cost including hedging for each generating facility. The report examined the total cost of hedging on a company basis and looked at the impact and cost of hedging at the individual customer level. By comparison, Progress Energy generates approximately 8% of its electricity from natural gas generation and hedges 40% of the fuel purchased compared to PacifiCorp's 12% gas generation and up to [redacted] hedging.

Q: Mr. Apperson is critical of your analysis and the use of the EIA Annual Energy outlook. How do you respond?

A: He is correct in stating that the EIA forecast was changed in 2009 based on the changing market conditions. His analysis however seems to prove the concern of many interveners in this case that the Company's current program is not able to adapt to changing market conditions. In rebuttal testimony he states;

> The Company executed the majority of its natural gas hedges for the test period prior to 2009; thus, its hedges were prudent given expectations at the time of execution.[12]

Parties have been concerned for some time that the current program is not flexible enough to adapt to changing market conditions and that contracts are purchased too far in advance. Even after EIA had revised the forecast down in 2009 and continued to lower the subsequent forecasts in 2010 and 2011, there has been no review or change to the current program. The Company has not been able to take advantage of the reduction in fuel cost that would benefit both the Company and rate payers.

Q: How do you respond to the criticism of your analysis of the correlation between the gas and electric hedging?

A: Mr. Bird indicates in his testimony that the Company manages its net energy position to take advantage of the natural offsets between its long power and short natural gas positions. No one has disputed that the Company should take advantage of the offset,

[11] Docket No. 2011-1-E, The Office of Regulatory Staff, Direct Testimony and Exhibits of Michael L. Seaman-Huynh, June 2, 2011.
[12] Rebuttal Testimony of John A. Apperson, p. 16.

however the difference between the Company's long power and short natural gas positions is changing. Mr. Apperson's testimony has validated some of the Division's concerns relating to the natural offset and volume differences between the natural gas and the electric contracts. He states:

> The volume of natural gas hedging in relation to electricity hedging will naturally be greater. Further one should expect in such circumstances that the net power cost impacts of the Company's natural gas hedges will exceed the net power cost impacts of the Company's electricity hedges.[13]

To the Division, this suggests a need to review gas and electric contracts as separate programs to maximize gains and minimize potential losses for both commodities prior to looking at the natural offset between the two positions.

Q: In Mr. Stefan A. Bird's testimony he indicated that there had been a reduction in the four years forward hedging percentage as a result of the reduction in the price of natural gas. Were you aware of this change and has this been communicated to the Division or the Commission?

A: No. This is the first time this issue has been addressed by the Company and the Division has not seen any reporting from the Company to indicate this change. However, the testimony appears to be in conflict with the response to data requests previously submitted.

> **DPU Data Request 20.19 -** The current forward price curve indicates fairly stable natural gas prices in future years. With the abundance of shale natural gas and the projected prices, will that have an impact on the current hedging strategy?

[13] Rebuttal Testimony of John A. Apperson, p. 24.

> **Response to DPU Data Request 20.19 -** The Company does not anticipate any change in hedge strategy based on current price projections. While the current forward price curve indicates projections of stable price in future years, history has proven that this can change radically. The Company anticipates maintaining a hedging strategy that manages the impact of changing natural gas prices on net power costs within acceptable tolerances as defined by current risk management policy and practices in the current front office procedures and practices.

> **DPU Data Request 20.20 -** With the historical and projected reduction in the amount of electric sales, please provide an explanation of the potential impact to the current hedging strategy.

> **Response to DPU Data Request 20.20** The Company does not anticipate any changes to its hedge strategy as a result of a shorter open electricity position, (i.e., the Company anticipates no change to the hedge targets measured as a percentage of the weighted net power costs nor to the to-expiry value-at-risk methodology).

Mr Bird has referred to the new TEVaR risk metric that was introduced in a technical conference May 25, 2010. This was presented as a mechanism to improve the transparency of the hedging program and risk exposure. It is unclear to the Division how this program has improved the transparency of the hedging program since no changes have taken place and no results have been reported to the Division.

Q: Can you explain why you believe that it is best to look at the gas swaps based on the price per MMBtu instead of a straight dollar value reduction?

A: Interveners in this case have used various calculation methods to come up with a dollar amount for disallowance on swap transactions. While different calculations have been used, the net results are similar. These calculations look at the total cost and then deduct a dollar amount or percentage from the total. This will work on a one time basis but does not establish a framework that can be used in the future. Instead of using a percentage of the total cost for disallowance, the Division attempted to estimate a range of prices calculated per MMBtu that could be allowed in rates. This calculation method could be used in future rate cases and could be used in connection with the future EBA calculation. The Company's projected cost per MMBtu could be compared to the forecast price to determine the hedging premium. Guidelines and tolerance limits could be established to limit the allowed premium for swap transactions.

Q: Do you have any additional information on NPC that you would like to include with this testimony?

A: Yes. DPU Exhibit 11.1 SR – RR is a comparison of the actual NPC to the forecast values for July 2010 through April 2011. The forecast amount is from the UT GRC June 2011 (GOLD) 2010-12-27 forecast information. Actual NPC information is provided by the Company on a monthly basis with the most recent actual information through April 2011.

When comparing the actual cost to the forecast, it is informative to review the difference in the individual line items included in the total NPC. For the 10-month July to April 2011 period, total NPC is $20.2 million higher than forecast while the coal fuel expense is $66.0 million lower and the gas burn expense including swaps is $62.2 million lower than forecast. Fuel costs have been identified as the primary driver for the projected increase in NPC however both categories are lower than the projected amounts for the first 10 months. It appears the purchases and sales are having a greater impact on NPC than fuel costs for the period under review. The individual components of NPC should be reviewed since they could have an impact on the future EBA calculations. While there has been a 15.2% decrease in the actual gas cost and an 11.4% decrease in coal cost compared to forecast, the total NPC has increased. This downward trend in the projected quantity of natural gas supports the recommendation from the Division and other parties to hedge less than 100% of the forecast requirement. This would allow for quantity fluctuations due to changing demand or changes in the economic conditions.

Q: Has the Company addressed the concern that the current hedging program does not include cost minimization as part of the overall strategy?

A: No. This issue has been brought up by several parties in this case and it has been brought up in other dockets as well. Mr. Bird indicates in his testimony:

> The goals of the risk management program are to: (1) ensure that reliable power is available to serve customers; (2) reduce net power cost volatility; and (3) protect customers from significant risks.[14]

[14] Rebuttal Testimony of Stefan A. Bird, p. 15.

The Commission ruled in the Questar Gas case that cost consideration should be included as part of the purchase strategy along with reliability and price stability.[15] This does not appear to be a consideration for PacifiCorp.

Q: How do you respond to the claim that the Company has followed the guidelines outlined in the risk management policy and should not be criticized or penalized for following its own plan?

A: The Company does have a hedging program in place and has set up a number of guidelines and procedures which have been examined by the Division's consultants. While the guidelines are in place, they have not been reviewed by the Commission to determine if they are in the public interest. The Company has documented these guidelines internally but does not report the actual results to the Commission or the Division. Since the Company did not violate the guidelines during the recent period of extreme price volatility in the natural gas prices, it can be argued that the loss parameters are too broad to be useful or meaningful. For comparison, if the speed limit is set at 100 mph, the chance of getting a speeding ticket is pretty low.

Q: How do you respond to Mr. Bird's claim that the DPU's analysis is incomplete and misleading and takes a short term perspective?

A: Mr. Bird is critical of the DPU analysis and indicates it looks only at recent developments and does not take a long-term perspective. In economics, the short term (or run) is defined as a period short enough such that at least one input is fixed. The long term is define as a period of time long enough such that all inputs are variable. In this respect, the Division's view and consistent position has been more of a long-term view. The Division has consistently recommended that the Commission direct the Company to produce a hedging policy that would be flexible and would allow the Company to react to changing market conditions.

The Division is not looking at just the current period and has expressed concern about the hedging program in this and in other dockets. Shale gas development for example, has been going on for several years. The EIA natural gas price forecast included in

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[15] Questar Gas Order in Docket Nos. 00-057-08 and 00-057-10 p. 7.

previous testimony shows the 2011 forecast lower than the 2010 and 2009 forecasts. The Company has known for several years that long term contracts were expiring and has not addressed these issues. This is not a new or short-term perspective.

Q: Do you still believe an adjustment for swaps and a disallowance is appropriate?

A: Yes. Based on the information presented above, the Company has not responded to the changing conditions both inside and outside of their control. The Commission has stated that a general rate case is the appropriate proceeding to determine if the Company is providing the least-cost, least-risk adjusted service to Utah customers.[16] The Company should not be allowed to recover all of these costs when they have not taken the appropriate steps to review or modify the current hedging program. With the implementation of the EBA scheduled to begin at the conclusion of this rate case, determining the appropriate costs to be include in base rates becomes even more important

Q: Do you have any changes to the conclusions and recommendations identified in your original testimony?

A: No. The Company has presented a great deal of additional information on hedging in the rebuttal testimony. However, the Company has not provided evidence to indicate that the current amount or the duration of the hedging program provides the appropriate balance of risk between the Company and ratepayers. The current hedging program has not been flexible enough and has not been able to adapt to the changes that have occurred in the natural gas market. Even though both internal and external conditions have changed, the Company has not completed a review of the program and has not considered the long-term cost or risks to rate payers.

In the EBA order the Commission stated that it will not provide standards or targets, or set limits on the components of power cost.[17] The absence of any guidance or direction from the Commission creates uncertainty for the Company and the possibility of unintended consequences. In Mr. Bird's rebuttal testimony he states;

[16] Docket No. 09-035-15 ECAM Order, p. 73.
[17] Docket No. 09-035-15 ECAM Order, p. 72.

> The Company welcomes Commission feedback particularly in regard to going forward risk tolerances, any other aspect of the Company's risk management policy and hedging program, and any type of reporting that the Commission may desire.[18]

This would indicate that the Company would like direction and guidance from the Commission in order to establish future guidelines.

The Division recommends and requests that the Commission issue an order that: (1) Directs the Company to complete an analysis and review of specific investment vehicles currently available such as options, caps, collars and their associated cost. (2) Orders the Company to prepare a hedging decision protocol and a method to determine when the use of other products would be appropriate to incorporate into the current program. (3) Instructs the Company to determine the hedging goals and strategy for electric and natural gas and structure them with separate guidelines. The goals should consider both the interest of the Company and rate payers. (4) Orders the Company to complete a review of the quantity and duration of swap contracts in future years. (5) Establishes the type and frequency of the reporting to the Commission and the Division.

As stated in previous testimony, the Division recommends that the Company file a comprehensive hedging plan with the Commission every two years. The plan should include the Company's current hedging goals and strategies for both natural gas and electricity along with estimates for market purchases.

Q: Does this conclude your surrebuttal testimony?

A: Yes.

[18] Rebuttal Testimony of Stefan A. Bird, p. 37.