Docket No. 12-035-67
UIEC Ex. ___ (JRM-3)

ORIGINAL

PUBLIC

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

Pre-filed Direct Testimony

of

Douglas D. Wheelwright

on Behalf of

Utah Division of Public Utilities

May 26, 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: What is the purpose of your testimony?

A: The Division believes that PacifiCorp's (" Company") current hedging practices have created significant additional expense to the projected total net power cost. The current hedging program does not provide enough flexibility and the Company has not recognized the internal and external changes in market conditions. My testimony will be in support of the Division's consultant, Mark Crisp who has looked specifically at what other utilities and commissions throughout the country are doing with their hedging programs.

Q: Can you summarize the Division's position on the current hedging practices and provide recommendations to the Commission?

A: The Division has reviewed the information provided by the Company and by the Division consultant and has determined that the Company should assume a portion of the additional costs associated with the swap contracts and should not be allowed to recover the full amount requested. The Company has not been able to demonstrate that the current hedging policies and practices provide the appropriate balance of risk to both the Company and ratepayers. The existing hedging strategy has been designed for price stability and does not adequately consider the potential cost impact. The current program creates additional cost to ratepayers and does not provide a mechanism to allow for possible cost reductions that could potentially benefit both the Company and ratepayers. Using financial swap transactions to hedge up to [redacted] of the price volatility does not provide enough flexibility to allow for changing load requirements or changes in market conditions. The program creates price stability for rate making purposes but reduces the incentive for the Company to look for possible cost savings opportunities. It is the position of the Division that the Company has not been prudent and should not be allowed to recover the full amount identified as swap costs. The Division is proposing a disallowance on swaps included in net power costs of $57,948,207 in a system-wide basis with $25,051,494 allocated to Utah.

Q: Will you identify the Division's concerns?

A: Several issues related to hedging have been addressed by various parties in previous rate cases,[1] in the EBA docket,[2] and in a separate docket created to address natural gas price risk and hedging practices.[3] In previous testimony, the Division and other parties have provided evidence and made recommendations to modify the Company's current program and have asked the Commission to establish standards or guidelines and create a review process.

In the recent EBA order, the Commission indicated it would not establish standards or targets, or set limits on the components of net power cost. The order further states that an appropriate venue to look at the inclusion or disallowance of costs associated with financial hedges is in a general rate case.[4]

The current practice of using financial swaps to hedge the future natural gas price is designed for an environment of increasing natural gas prices. With the increase in the availability of natural gas due to increased shale gas production, the price of natural gas

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[1] Docket No. 09-035-23.
[2] Docket No. 09-035-15.
[3] Docket No. 09-035-21.
[4] Docket No. 09-035-15 ECAM Order p.72.

While this may be the Company's goal, the projected cost of the hedging program is adding to the total Net Power Cost (NPC). Cost minimization does not appear to be a consideration in the current program.

Q: What does the Company identify that should be included in the total hedging program?

A: This is where the confusion begins. As a broad definition of hedging, the Company includes financial swaps for electric and gas along with the physical transactions for both gas and electric. For the test year the Company has identified the value of the natural gas and electric swap transactions in the UT GRC June 2012 (GOLD) report. The gas and electric swap transactions are the primary focus of my analysis.

Q: How does the price volatility of natural gas affect the Company?

A: PacifiCorp natural gas-fired generating facilities account for 21% of the total net owned generating capacity but only 12% of the total energy. In determining whether to dispatch its natural gas-fired facilities, PacifiCorp considers, among other factors, its operating requirements to balance electricity supply and demand and the current spark spread. Spark spread is the difference between the wholesale market price of electricity at any given hour and the cost to convert natural gas to electricity.[13] The decision to dispatch the natural gas facilities is affected by the volatility of the price of natural gas. A change in the forward price curve will change the spark spread and the decision to dispatch a natural gas facility or purchase electricity.

Q: What is the impact of swap transactions that are included in NPC?

A: In the UT GRC June 2012 (Gold) report, natural gas swaps add $160.7 million to NPC while the electric swaps reduce NPC by $61.7 for a net increase of $99.0 million. The majority of the increase occurs in the last six months of the test year and, thus, the impact of the swap transactions increases significantly in the last six months of the test period. As of December 31, 2011, the net of electric and gas swaps is $8,231,437.

Q: How does the forecast compare with the historical values for swaps?

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[13] PacifiCorp, 2009 10-K Report, p. 10.

averages calculations to the right of the test year months. Using this template I have calculated the anticipated upper and lower price band forecasts at various confidence levels. Page 2 of DPU Exhibit 11.1 D-RR identifies the forecast upper and lower natural gas price range for confidence intervals from 50% to 99%.

To review the projected price included in the test year I have compared the projected price provided by the Company to the EIA forecast price range. Using a 95% confidence estimate, the EIA forecast produces a forecast price range from a low of $2.95 to a high of $7.61. This places the test year forecast price of $7.23 on the high end of the range and significantly above the average settled price of $4.73. Thus, it appears that the actions of the Company and the current hedging policy have shifted nearly all of the price risk to ratepayers.

Q: How does the hedging strategy at PacifiCorp compare to the strategy used by Questar Gas Company?

A: Questar Gas Company ("Questar")prepares an annual hedging plan and makes a presentation to the Commission prior to implementation. Over the last 5 years, Questar has entered into fixed price agreements for approximately 63% of the forecast winter heating season need and has purchased the remaining quantity on the spot market. This has allowed Questar to take advantage of the recent drop in the market price which has been a benefit to both Questar and to rate payers. In the Questar Gas pass-through docket the Commission indicated that Questar should consider cost, reliability and price stability as the three factors that should influence a gas purchase strategy.[19]

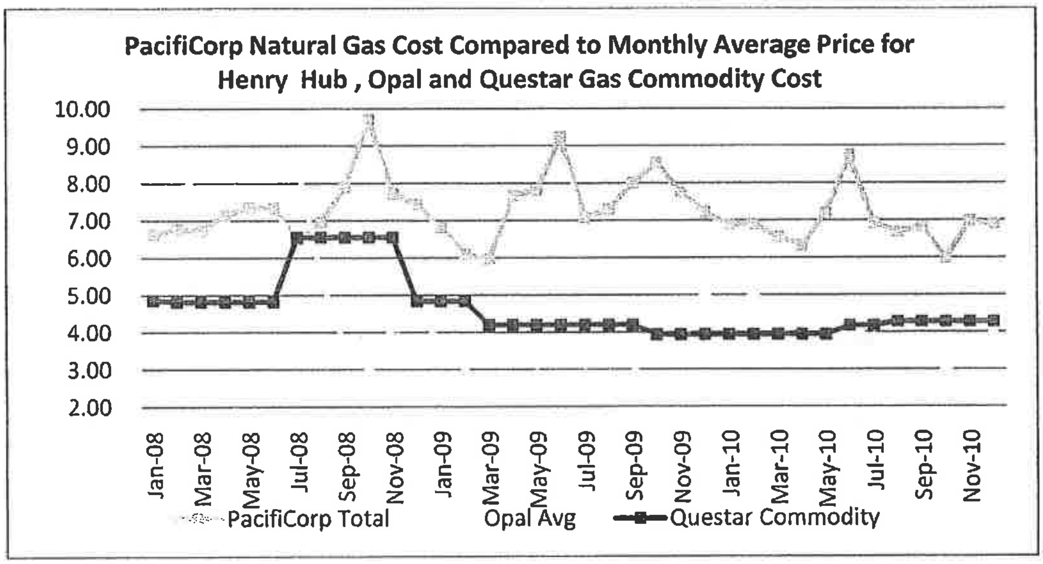
Q: How does the price for the natural gas commodity consumed by PacifiCorp ratepayers compare to the price of natural gas consumed by Questar's ratepayers?

A: Chart 5 below is summary of the cost for natural gas paid by ratepayers of PacifiCorp and ratepayers of Questar compared to the Opal spot market price. The actual values used for the Questar information has been taken from information provided in the 191

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

account. By using a shorter time horizon and allowing for some market purchases, Questar has been able to stabilize prices and still take advantage of the reduction in gas prices in recent years. Questar includes the WEXPRO production as part of their fixed price contracts. This has helped to keep the price down, but the remaining 37% has been purchased at market price.

Chart 5



Q: What is the Company currently paying for natural gas contracts in future years?

A: In response to DPU data request 32.3, the Company identified a few of the contracts that have been completed in the last 6 months. [redacted] which confirms the flat nature of the forward markets. While these new contract prices are lower than the historical information provided, due to the long term nature of the program it will take several years to realize a reduction in the price per MMBtu.

Q: Are you suggesting that the Company completely abandon its hedging program?

A: Not at all. The Division believes there is a benefit to hedging in order to stabilize price and minimize dramatic price spikes that would affect both the Company and ratepayers.

While the current projections are for stable gas prices, there is a possibility that natural disasters or economic conditions could change causing prices to increase rapidly. For example, environmental concerns related to the "fracking" process used in shale gas recovery could affect the future price along with other environmental or natural resource issues. Therefore, the Division is supportive of a certain level of hedging and recognizes that there will be costs associated with any hedging program.

Nevertheless, the Division is concerned that the current hedging strategy has been conducted without the scrutiny or approval of regulators and has not been explicitly determined to be in the best interest of the Company or ratepayers. Additionally, the Division is concerned that the Company's current hedging program and practices do not provide an appropriate degree of flexibility to adapt to changing conditions and are weighted too heavily toward price stability at the expense of cost minimization. With that said, the Division recognizes that there are likely as many different hedging programs as there are electric utility companies and probably no perfect hedging program exists.

Q: How does the Division interpret the current EBA order that allows swaps to be included in base rates but excluded from the EBA calcluation?

A: This is a bit confusing. The Commission has been asked to review its decision to include or exclude swap transactions from the EBA, but has not yet acted.. The EBA order states;

> …swap transactions should be excluded from the calculation of both base and actual net power costs. We agree swap transactions do not track well with the statutory definition of energy cost. Swap transactions currently approved will remain in basic customer rates. We also conclude these transactions must be reviewed and approved in each general rate case, which is an appropriate proceeding for determining the prudence of Company decisions. [20]

The order indicates that swap transactions are excluded from the base and the balancing calculation but swaps already approved and included can remain in rates. The inclusion of any future swap transactions must be reviewed and approved in a general rate cases.

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[20] Docket No. 09-035-15, ECAM Order p 75.