BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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	))))))	DOCKET NO. 10-035-124 DPU EXHIBIT 13.0 D-RR

PRE-FILED DIRECT TESTIMONY

MARK W. CRISP, PE

ON BEHALF OF THE

UTAH DIVISION OF PUBLIC UTILITIES

May 26, 2011

PUBLIC

INTRODUCTION

Q. Please state your name, business address, employer, and current position or title for the record.

A. My name is Mark W. Crisp, and my business address is 1100 Circle 75 Parkway, Suite 1530, Atlanta, Georgia 30339. I am Managing Consultant for C. H. Guernsey & Co. I am providing testimony on behalf of the Utah Division of Public Utilities (DPU).

Q. Please describe your education and work experience.

A. I received a Bachelor of Civil Engineering degree from the Georgia Institute of Technology in 1978. In addition to my engineering education, I am a Registered Professional Engineer (PE) in several states. In 1980, I received a Master of Business Administration from the University of Arkansas at Little Rock with a concentration in Finance and Economics. Following completion of my formal education, I was employed for 2 years by Arkansas Power & Light (Middle South Utilities now Entergy – Arkansas) and 15 years by Georgia Power Company/Southern Company. During this time, I completed assignments in the planning, siting, design, construction, and operations of nuclear, coal, gas, and hydroelectric generating plants. In addition to my utility operating experience, I was also responsible for technical due diligence on Southern Electric International's ("SEI") Acquisition Team. In this capacity I was responsible for evaluating all fuel, operating, environmental, staffing and operational aspects of power generating facilities, worldwide, that were the focus of SEI (Southern Company's) acquisition strategy.

Following my employment in the utility industry, I became a consultant providing services to electric and natural gas utilities, as well as regulatory bodies throughout the United States and internationally.

A copy of my résumé is included in DPU Exhibit 13.1.

Q. Where have you testified before?

A. I have provided expert testimony before the public utility commissions in Georgia, South Carolina and Maryland, as well as before the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), in state and federal courts, and before the U.S. Congress.

Q. Have you appeared before the Public Service Commission (Commission) of Utah in the past?

A. No, I have not.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address the Gas Hedging program currently employed by Rocky Mountain Power ("Company or RMP"), a division of PacifiCorp.

Q. Will you briefly describe the Hedging Program of the Company?

A. PacificCorp Energy, an unincorporated division of PacifiCorp, a subsidiary of MidAmerican Energy Holdings Company, has developed what is termed its *Commercial & Trading Risk Management Policy*. Within this policy, PacifiCorp manages transactions for the procurement of natural gas fuel stocks for the Company's electric generating fleet, as well as electric swaps. In the instant case, Commercial & Trading manages this process for the Company. The overall goal of the natural gas hedging program appears to establish a firm financial commitment, through rate setting, of the forecast costs necessary to "lock-in" gas costs used in the "Test Year" analysis the Company submits as a part of their current rate proceeding. This cost is based on the forecast volume of gas to be used in the Test Year and this, by default, establishes the volume of gas to be hedged.

This volume of gas can be greatly affected by seasonal temperature variations. In other words, the volume requirement forecasted may be close to that hedged if the Test Year is "near average." However, if seasonal temperature variations cause increased heating or cooling degree days that deviate from the average, the volume of gas actually procured in the hedging program will either be more than necessary, if seasonal variation during the winter is warmer than forecast or additional volumes are necessary if the seasonal variation during the winter is cooler than forecast. If the seasonal variation is affected by warmer than forecast temperatures or the forecast is understated for any reason, such as a higher than forecast load growth, then the Company will likely need to purchase additional gas or make (likely expensive) purchases on the wholesale electric market.

If summer temperatures are cooler or winter temperatures warmer than expected, then the Company may have excess gas not burned that may require a "sell back" to the supplier in a physical transaction or the Company may simply lose money on a financial hedge during the settlements by having committed to purchase higher than necessary gas volumes. Unlike coal, the Company does not maintain sufficient gas storage capacity capable of providing storage of quantities procured in excess of demand and holding until demand catches up with supply nor is there storage significantly large enough to store gas to augment pipeline supplies during demand spikes.

The Company's hedging program clearly articulates that as much as [redacted] of the gas needed in the first two years of a contract will be purchased to provide for "stability" of pricing and quantity. However, this process in conjunction with the General Rate Case assures the Company a revenue stream to support the purchase of the volume of gas regardless of whether the gas is used or not. If the gas is not used then the Company must sell back the excess to the supplier at a variable rate that greatly favors the supplier. In these cases, the hedging program actually creates an added expense the rate payers must absorb. In response to UIEC data request 21.4, the Company has indicated that as of March 31, 2011 they have hedged [redacted] of the test year natural gas price exposure with swap contracts.

Q. How does the Company use different products to manage different types of risk?

A. The Company uses financial hedges to manage the price volatility and physical hedges to manage the volumes. Exposure to increases in natural gas supply costs are hedged with financial swap contracts that settle in cash based on the difference between a fixed price in the contract and a floating market-based price.

In a "simple swap" transaction, PacifiCorp purchases a contract for a specific date and quantity in the future. If the market price is higher than an agreed-upon contract price at the expiration date, the counterparty will pay the difference to PacifiCorp. However, if the market price is lower than the contract price, PacifiCorp is required to pay the difference to the counterparty. This financial product locks both parties into the agreed-upon price, regardless of the actual market price at the time the physical product is purchased.

This arrangement works in the Company's favor in a rising price environment. In a declining price environment, the hedge offers no price protection to the Company since they are locked in at the higher price. A negative aspect of this is that a declining price can change the market value of the contract which could require the Company to make a cash collateral payment to the counterparty.

PacifiCorp manages its natural gas volume requirements by entering into forward commitments for physical delivery of natural gas. These contracts are not completed as far into the future as the financial transactions. There is some confusion concerning the actual percentages of physical and financial hedging done by the Company. Due to the existence of multiple contracts, with variable contract obligations, in effect at any one time and the complexity of each contract, and the "highly confidential" status of the contracts, the Commission and DPU are in a difficult position to monitor the hedging program in terms of their regulatory oversight responsibilities. The Commission and

DPU must have transparent access to the actual hedging contracts, either physical or financial, and must be able to reconcile all contracts on a periodic basis, i.e, quarterly.

Q. Are there other negative aspects to the hedging program?

A. Yes, the hedging program uses financial products commonly referred to as "swaps" that are contractual obligations, either financial or physical, established between the Company and a counterparty. A gas swap occurs when the Company contracts for a specific volume and price of gas. Contracts for the delivery of the physical gas are established with the gas providers. During the course of an operating year, there will be financial hedges and physical hedges. The financial hedge occurs when the Company contracts for supplies and agrees on pricing terms but does not take physical control of the gas until it is required for burn. The physical hedge occurs when the Company takes physical control of the purchased gas. In either case, if the volume of obligated gas is not taken from the supplier or is taken but not burned, then the Company can and does sell back to the supplier any "unused" gas at a price that is much lower than the equivalent price the Company contracted to purchase the gas, originally. The Company forecasts the value of the swaps based on the forward price curve and places them in the rate case for recovery.

Q. Is this a complete synopsis of the hedging program?

A. No, the hedging program is an extremely complicated technical and financial procedure requiring significant resources to manage properly. The aforementioned synopsis is a "boiled down" description of the natural gas process described in two policies the Company included in well over a hundred pages of text plus untold pages of Appendices provided in data requests. For those of us that spend considerable time with hedging programs, the process is somewhat more easily understood.

The Company compounds the difficult nature of monitoring their hedging program by placing a "highly confidential" seal on the actual financial and transaction data. The effect of the difficult and confusing hedging protocol along with the confidential "tag" on data creates a process that is neither transparent nor in the best interest of the rate payer. The Company also employs the use of "stop loss limits" to minimize financial losses however, again these are "highly confidential" making it once again, impossible to monitor or review outside of a formal rate case or data requests. The hedge process as a risk management tool should be a transparent process that is reported to the Commission on a quarterly basis so that determinations of costs and objectives can be monitored and reevaluated if the objectives and cost impacts are determined to be not in the best interest of the rate customers.

Q. What is your assessment of the Commercial & Trading Risk Management Policy or the direction for hedging practices?

A. The *Commercial & Trading Risk Management Policy* manual is extremely detailed and thorough. However, the detail and thoroughness of the hedging procedures injects confusion especially for those not actively participating in the practice on a day to day basis. Only those within the Company that track the hedging program for the Company are in a position to explain the day to day financial obligations or physical obligations, particularly if the Company does not share the terms and conditions of the gas contracts with the Commission.

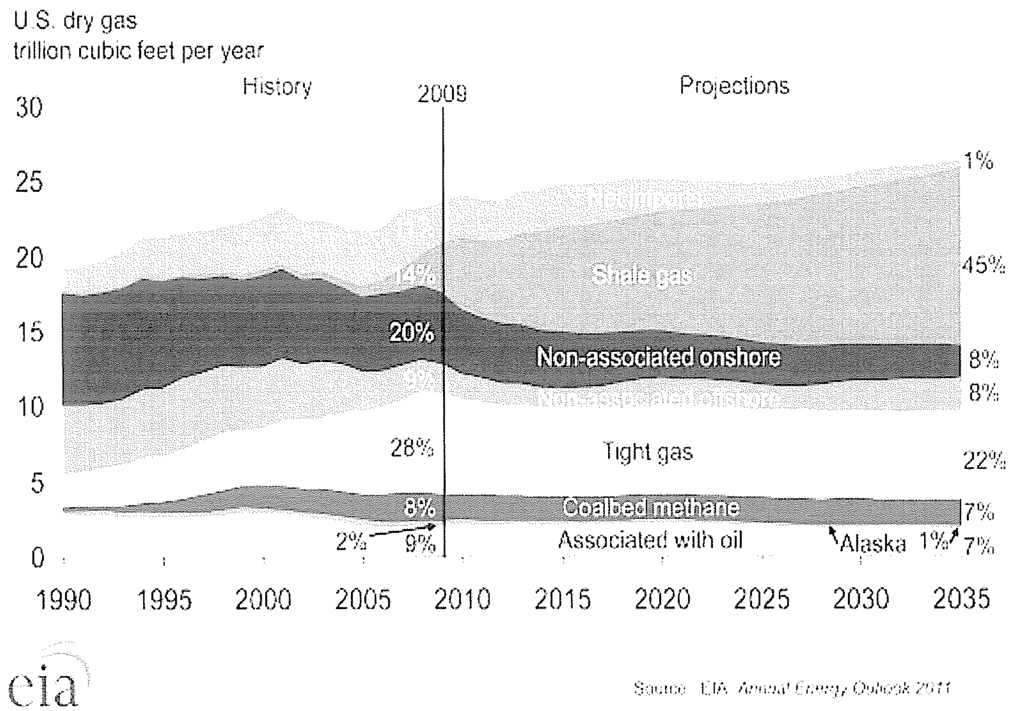
The use of the gas hedging practice for the procurement of upwards of [redacted] of the natural gas stocks places an undue burden on the Commission, DPU, and other interested parties in attempting to balance Company risk with customer rate impacts. The process is further exacerbated with the addition of multiple gas contracts with multiple start and end dates. It is extremely difficult for the Company to "track" gas volumetric moves by supplier or a single supplier with multiple contracts and the associated costs. For this same reason, it is practically impossible for the Commission and others to properly track gas movements and pricing impacts to rate payers. To further complicate the matter, there is no formal reporting mechanism for the Company to inform the Commission or to readjust rates should the gas market hit a downturn creating a position that the Company is over-collecting due to the reduced gas price. For these reasons, I would suggest the current hedging policy is imprudent with regards to equitably sharing risk between the Company and the rate customer, minimizing upward pressure on rates, and providing rate relief if gas prices fall below those forecasted in the general rate case for physical purchases and swaps.

Q. If the Risk Management Policy is so difficult, why does the Company continue to use it for gas hedging?

A. The Company employees a significant number of personnel trained in the use of the Policy. They are completely comfortable with the Policy since they are fully engaged with its use on a daily basis. The Policy, as it is used today, provides the Company with a significant financial benefit by including all of the costs of gas purchases, swaps, etc in the rate case for recovery during the subsequent rate-effective period. It provides a nearly 100% risk avoidance for the Company while at the same time placing nearly 100% of adverse risk on the rate paying customers.

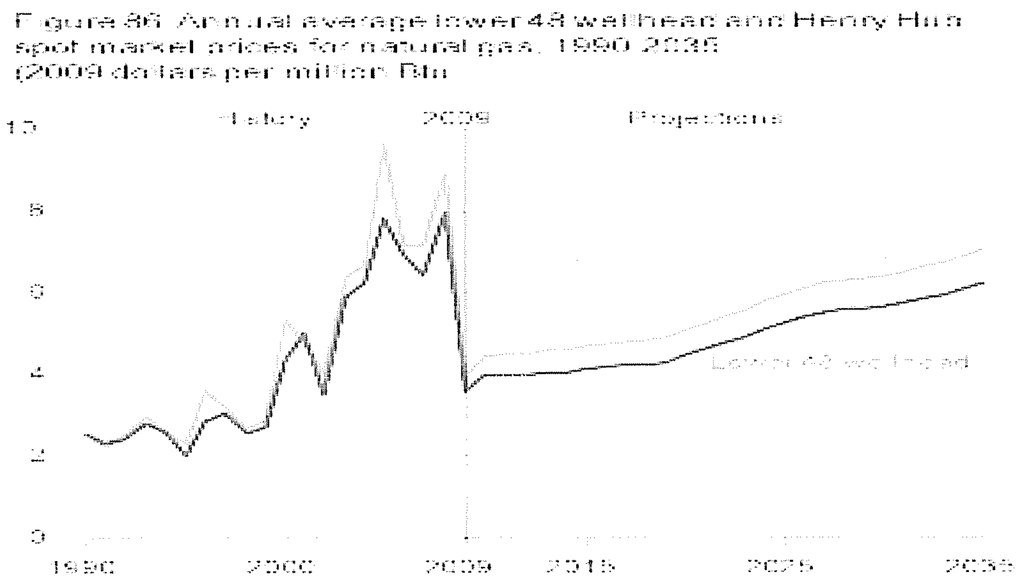
Q. But does not the risk policy provide some assurance of fuel price stability for a known volatile commodity?

A. In years past, natural gas was an extremely volatile commodity. During certain periods of time and following certain external events, it was not unusual to see natural gas prices "spike" by 100%, 200% or even higher in extreme cases. However, several factors have entered the natural gas market and are providing cost stabilization. One of the single most important of these issues is the increase in Shale Gas production in the United States with a commensurate reduced reliance on imports. The following Table illustrates the influence of Shale Gas on the market as forecast by the U.S. Energy Information Administration ("EIA").

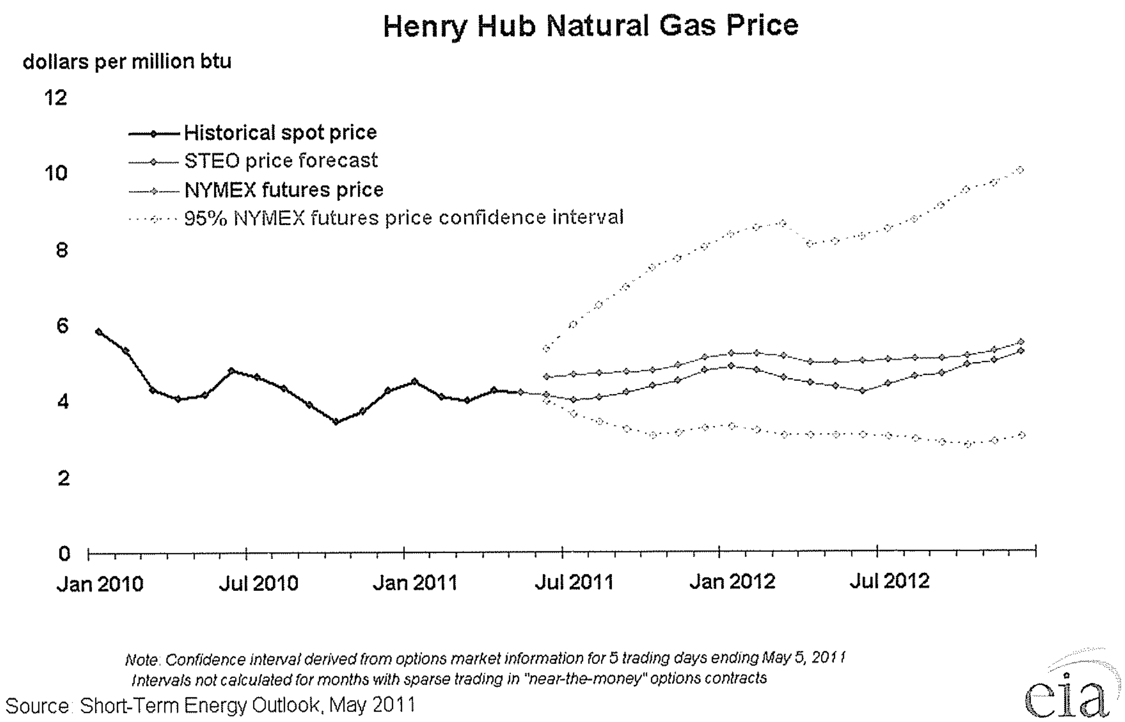


Q. What does this increase in Shale Gas production mean for price volatility or stabilization?

A. The increase in production of domestic natural gas concurrent with the technology to fracture shale gas reservoirs creates a significantly important stabilization effect on U.S. natural gas prices over the long term. As a matter of fact, the EIA is forecasting the spot price of natural gas to increase by only $2 /million Btu over the next 25 years (See table below).



In comparison, the short-term price forecast indicates an even greater stability in pricing. See table below.



Q. Please explain how this relates to the Company's hedging policy.

A. As discussed earlier, hedging is a process used by the Company ostensibly to provide protection from price instability. However, as shown above, the natural gas price is stabilizing, naturally, by increases in domestic production, and reduced reliance on international product, including the reduction in LNG imports. Based on these forecasts, there is reason to re-evaluate the hedging process and certainly justifiable reasoning to disallow costs for natural gas swaps.

Q. Why do you suggest justifiable reasoning to disallow natural gas swaps?

A. The current risk mitigation plan of the Company does not provide any incentive for the Company to provide an accurate or defensible natural gas hedging program. They merely include in their Test Year financials a forecast of what it will cost them to purchase gas during the Test Year and they include another "line item" of what they forecast will be their expense for natural gas swaps. Neither the Company's hedging plan nor its reporting requirements to the Commission require the Company to report its forecast accuracy and comparison of forecast costs to incurred costs as they proceed through the "operating year." There is little to no reporting of the various gas contracts, terms and conditions, fixed pricing on the purchase commitment end or indexed price on the return or swap end. While we recognize and appreciate the Commission has articulated it does not want to "micro-manage" the Company, the combination of gas and electric swaps amount to nearly $100 million in the current rate case. Due to the Company's claim of "highly confidential" protection of this information, it is realistically impossible for the Commission or DPU to monitor the hedging program during the execution phase of the contracts and swaps. The Company is already requesting favorable rate treatment of up to [redacted] of their gas purchases in this rate case. Their request also includes rate relief for their forecasted swaps. If granted, this would provide the Company with an absolute assurance of rate coverage for all gas transactions. The risk and rate burden would fall exclusively on the shoulders of the rate paying customers.

The Commission has recognized this to be an onerous situation for the customers in the Commission order in Docket No. 09-035-15, Energy Cost Adjustment Mechanism ("ECAM") or Energy Balancing Account by disallowing all natural gas and electric swaps. While this Order is under rehearing, it, nonetheless, emphasizes the fact that the Commission understands the complexity of the hedging program, recognizes the rate payer carries the full risk of the gas purchases program of the Company while the Company enjoys, as close as is possible, a risk-free natural gas purchasing program with little to no incentives to be aggressive with natural gas purchasing forecasting or contract negotiations. Disallowance of the natural gas swaps and electric swaps will return a portion of the risk to the Company, where it should reside and remove this burden from the rate payer.

Q. What is your understanding of the status of gas hedging programs in other regulated jurisdictions?

A. Exhibit 13.2 of my testimony is a compilation of our direct interviews with 25 of the State regulatory bodies concerning natural gas hedging programs under their jurisdiction. Of the 25 States, 19 have allowed some form of hedging. However, policies within the hedging programs differ considerably from jurisdiction to jurisdiction. Most all jurisdictions require the utility to file a monthly or quarterly review of the hedging activities, including costs. These filings are in addition to specific filings within a general rate case or in a fuel proceeding. In 9 of the 25 cases the Commissions are evaluating whether to suspend or eliminate the hedging program, primarily due to the stability of natural gas pricing. In a number of the states that are not looking into program modifications, there already is a limitation on the amount of gas that can be hedged, i.e., 25%, less than 75% or some other percentage. If the jurisdiction does not have a limitation, then there is a regulatory policy in effect that requires the company to submit their plan and forecast for regulatory approval on an annual or bi-annual basis. It is also quite clear, by reference, that these commissions are or have dealt with the complexity of monitoring hedging programs and have come to a similar conclusion that the companies must provide more transparency in their reporting to the commission of their hedging activities. In addition, these commissions have also recognized through their requirements to allow only percentages of the total gas requirement to be hedged, that risk should be shared by the company and the rate payer not borne totally by the rate customer. In jurisdictions where there is no limitation on the amount of hedging, these commissions have in-place requirements for the company to report the hedging activities, prepare and submit annual hedging plans, require an annual prudency hearing on hedging costs or some other mechanism that produces transparency and risk sharing, not 100% risk mitigation by burdening the rate payer.

Q. What is your recommendation concerning the Company's hedging program?

A. Based on all of the factors previously discussed, I recommend the Commission require the Company re-evaluate the hedging program in its entirety and bring to this Commission a revised hedging program, within 180 days of the conclusion of this docket, that:

- Produces a "sharing" of the risk between the Company and the rate customer;
- Produces a transparent methodology in which the Company prepares quarterly documentation of the hedging transactions, physical and financial, and
- Submits to the Commission and DPU comparisons tables, charts, or graphs of the actual hedging results compared with that forecast in the "Test Year." Deviations from the Test Year forecast will be identified and the logic behind the deviations will be provided to the Commission and the DPU. The deviations will be identified in both absolute numbers and percentages.

In order to effectuate an immediate shifting of some of the risk back to the Company and to create an incentive for the Company to aggressively manage their natural gas contracts, we propose the disallowance of the net of Natural Gas Swaps and Electric Swaps ($160,723,241 - $61,683,848) = $99,039,393 on a system-wide basis. The portion of the disallowance allocated to Utah rates would be $42,868,310. While I believe that disallowing the full amount is justified, the Division will articulate its position in Mr. Wheelwright's testimony.

Q. Does this conclude your testimony?

A. Yes.