BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Request of Rocky Mountain Power for Approval of Its Proposed Energy Cost Adjustment Mechanism its	**DOCKET NO. 09-035-15** **Exhibit No. DPU 2.0** **Testimony** **Douglas D. Wheelwright**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Testimony of

Douglas D. Wheelwright

REDACTED

June 16, 2010

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: The Division of Public Utilities.

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 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 purpose or my testimony is to present information and recommendations relating to PacifiCorp's current hedging policy and practices and market purchases.

Q. Why is this issue being addressed separately from the other portions of the ECAM case?

A. There has been a lack of understanding concerning the amount and duration of the current hedging program as well as the price fluctuation of the hedged contracts. Before the design phase of the ECAM can proceed, parties wanted to have a better understanding of how hedging is being used at the Company and the potential for recovery of these costs. For example, some parties have questioned whether an ECAM is necessary given the current level of Company hedging and the price stability it creates. Additionally, the costs that could flow through an ECAM are significantly affected by the level of hedging and the strategies employed by the Company. Maintenance of a high volume of hedging could mean that large gains and/or losses from hedging could flow through the ECAM. Potentially, in an ECAM environment the Company could stop hedging and subject ratepayers to the full degree of volatility in natural gas and electricity markets. Given the potential effects of hedging on the

ECAM, it would seem appropriate for the Commission to provide guidance or establish a mechanism for handling hedging. The Division called for such guidance in the recent rate case (Docket No. 09-035-23) and the potential for the establishment an ECAM has increased the concerns of other parties as well.

Q. Can you summarize the Division's finding and recommendations?

A. With regard to market purchases, the Division has been concerned for some time that the Company is putting ratepayers at risk by an over-reliance on wholesale electrical market purchases and front office transactions. The Company has not adequately modeled the potential risks it and ultimately ratepayers face by being subject to the whims of a potentially volatile and costly energy market.

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. The primary goal of the hedging program is to reduce the price volatility of commodities in order to stabilize prices two years in advance. The Company has not provided evidence that the current amount or the duration of the hedging reduces the appropriate amount of risk to the Company or to ratepayers.

A key part of the Company's hedging strategy is the relationship of the gas swaps with electric swaps. The Division feels that the Company and Commission should explore whether the Company should structure its overall swaps policy not as an electricity and natural gas combination, but rather as two separate strategies.

The Commission should direct the Company to complete an analysis and review of specific investment vehicles currently available such as options, caps, collars and their associated cost. This analysis should also include an examination of other mixes of contract types and durations. As part of this analysis the Company should prepare a hedging decision protocol and when the use of options would be appropriate to incorporate into the current program.

The Division would like to see the Company file a comprehensive hedging plan with the Commission every two years. The plan should include the current hedging goals and strategies for both natural gas and electricity along with estimates for market purchases. A broad energy policy approved by the Commission would provide guidance and direction to the trading department and have predetermined policies and procedures in place to deal with potential and significant changes in the market conditions.

MARKET PURCHASES ISSUES

Q. The Company's hedging practices is one of the two special issues the Office of Consumer Services raised in this docket. The other special issue concerns the Company's reliance on front office transactions, in other words, purchases of electric energy and capacity from the wholesale markets.[1] In Phase I, the Utah Public Service Commission issued an Order specifying that these two issues may be considered in Phase II.[2] Does the Division have a position regarding PacifiCorp's reliance on front office transactions?

A. Yes.

Q. Please explain the Division's position on this reliance on front office transactions?

A. The Division is concerned with the level of reliance on the wholesale markets. In its comments on the 2008 PacifiCorp Integrated Resource Plan (2008 IRP), the Division made the following comments:

> The Division has been concerned for some time that the Company is putting ratepayers at risk by an over-reliance on front office transactions and other third-party purchases. The Division raised this concern in its comments on the 2007 IRP and elsewhere. For its part, the Company in this IRP states that one of its corporate goals is to reduce reliance on front office

[1] Direct Testimony of Michele Beck, Docket No. 09-035-15, November 16, 2009, pp. 13-15.
[2] Order of the Utah Public Service Commission, Docket No. 09-035-15, dated February 8, 2010, p. 2. "In addition, we would like to see the two issues raised by the Office of Consumer Services addressed: namely, is the company's use of natural gas hedging and the level of and reliance on market energy affected by the use of an ECAM? We will continue this docket into Phase II to make this exploration together with all other relevant areas of inquiry."

> transactions and implicitly on other third party purchases. The Company implies that in this IRP it has made progress toward that goal.[3]

As suggested in the quotation, the Division's concern with the Company's reliance on front office transactions has been on-going for a number of years. While there are some benefits to the Company using these front office transactions as part of its strategy, the concern for the Division is that the Company has not been adequately modeling the potential risks it and ultimately ratepayers face by being subject to the whims of a potentially volatile and costly energy market.

Q. What has the Commission said relative to this issue?

A. In its Report and Order on the 2007 IRP, commenting on both the Company's planning reserve margin and the Division's concern that the Company will be to subject to market volatilty, the Commission concluded "Nonetheless, the IRP is the Company's planning document and it bears the risk for any unreasonable costs associated with this planning decision."[4] In its Report and Order on the 2008 IRP the Commission was even more direct in addressing the concerns of the Division, Office, UAE, and WRA:

> We are concerned with the Company's stated confidence in managing the risk associated with reliance on the market for a significant portion of its customers' power requirements, especially combined with its comfort with planning to a 12 percent planning reserve. These decisions appear to leave little room for forecast error related to prices and loads. Meanwhile, the Company is asking for an energy cost adjustment mechanism in a separate docket.[5] In part, the Company there argues it cannot effectively manage the risks, even one year out, of the costs associated with unexpected fuel prices, wholesale electric prices, and loads. At a minimum, we direct the Company to include the costs of hedging in its IRP analysis of resources that rely on fuels subject to volatile prices. We also direct the Company to perform sensitivity analysis to determine a hedging strategy which minimizes costs and risks for customers.

[3] Division Errata Report and Recommendations on 2008 IRP, Docket No. 09-2035-01, June 18, 2009, p. 32.
[4] Public Service Commission, Report and Order, Docket No. 07-2035-01, dated February 6, 2008, p. 17.
[5] Docket No. 09-035-15.

> Additionally, we direct the Company to include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely. We concur with the Office, the WECC is a reasonable source for this evaluation. We direct the Company to identify whether customers or shareholders will be expected to bear the risks associated with its reliance on the wholesale market. Finally, we direct the Company to discuss methods to augment the Company's stochastic analysis of this issue in an IRP public input meeting for inclusion in the next IRP or IRP update.[6]

Q. The Division indirectly quotes the Company as agreeing that reducing reliance on front office transactions is a corporate goal. What is the current status of that goal?

A. As demonstrated by the Division in its comments on the 2008 IRP,[7] the Company had actually increased its planned reliance on front office transactions between its 2007 and 2008 IRPs. In the 2008 IRP Update dated March 31, 2010, the Company is reducing its planned reliance on front office transactions over the 2008 IRP. The Company can accomplish this reduction due, in part, to the economic recession and relatively slow recovery currently underway. One aspect of the delays in acquiring new generating capacity is that the need for front office transactions continues to be pushed further out in the future.

Q. Does the potential introduction of an ECAM influence or change the Division's concerns about relying upon market purchases?

A. Quite the opposite. In the current rate recovery process, i.e. reliance upon rate cases to set rates, there is a built-in incentive for the Company to stabilize its costs in order to ensure that its actual costs do not exceed its projected costs. Normally one would expect this incentive to result in the Company's building more power plants and then locking in (to the extent possible) fuel costs. While the Company seems to have substantially accomplished the latter (for example through its hedging program), it has not responded to demand growth with an equivalent growth in owned resources. The Division is concerned that the introduction of an ECAM could reduce the Company's incentive to build (or purchase) resources to meet demand. If the Company has all or a substantial portion of its power purchases guaranteed

[6] Public Service Commission, Report and Order, Docket No. 09-2035-01, dated April 1, 2010, pp. 30-31.
[7] Id., p. 34.

for recovery (subject of course to prudence review), it is more likely to continue to rely upon market purchases rather than building new resources.

Q. Given the citations above, does the Division generally agree with the Office of Consumer Services that there is a need to address the issue of front office transactions?

A. Yes. However, as set forth in Mr. Peterson's earlier testimony in Phase I of this docket, the Division does not necessarily agree that dealing with the issue in the hedging or ECAM Dockets are necessarily the best places to consider the issue.[8] Nevertheless, the Division anticipates that other parties are likely to raise the issue in this docket per the Commission's June 7, 2010 scheduling order.

Q. How might concerns about market purchases be addressed at this point in the ECAM docket?

A. Presumably the Commission could exclude electricity market purchases from an ECAM, or perhaps only allow cost recovery for market purchases that cover a specific percentage of annual or peak load. The Division would be concerned, however, that such a prescriptive approach could result in less economic efficiency, such as generating power when purchases would be cheaper, or create an incentive to curtail load in circumstances when power is especially expensive. We feel that the Commission should be very careful to avoid creating a regulatory structure that does not allow the Company to use its best judgment in managing its day-to-day operations. However, it may be possible to address the issue of market purchases in the design of an ECAM in a way that maintains an incentive to acquire generating resources without at the same time creating perverse incentives or undesirable outcomes.

Q. Can you outline what the Division might recommend in the design stage of the ECAM Docket 09-035-15?

A. The Division's thinking in this matter is very preliminary at this time. But the ideas that are being considered relate to introducing mechanisms within the design of an ECAM that would provide incentives to the Company to reduce its reliance on front office transactions. Such

[8] Phase I Rebuttal Testimony of Charles E. Peterson, Docket No. 09-035-15, dated December 10, 2009, pp. 8-9.

mechanisms might include narrowing or expanding a dead band, or increasing or decreasing a sharing percentage based upon the Company's progress in reducing front office transactions.

Q. Can you give further details?

A. Not at this time. The discussions within the Division are very preliminary and what is ultimately proposed by the Division may have different mechanisms, or none at all, to deal with the front office transaction issue. I have nothing further to add at this point to the issue of reliance on front office transactions. However, the Division is likely to address this issue as part of its testimony on an ECAM design, which is due in August.

HEDGING ISSUES

Q. Are there any key policy issues regarding hedging that should be addressed in this proceeding?

A. Yes, the Division believes there are three key questions that the Commission needs to consider in this phase of the ECAM docket:

1. Should the Company continue to pursue its hedging strategy without any overt guidance or requirements from the Commission about what its hedging goals should be or what hedging strategies to pursue?
2. What is the goal of hedging? Should the goal give priority to (on the existing extreme) to cost stability or (on the other extreme) cost minimization – i.e. no hedging, or is there an appropriate middle ground that strikes a compromise between stability and cost.
3. What kind of guidance would be appropriate for the Commission to provide if it chose to do so?

Q. Has the Company provided information necessary to explain how the current hedging strategy provides protection from the volatile price of natural gas and electricity commodity?

A. The purpose of the Company's strategy is stability and predictability in its realized net power costs. The Company's strategy is not aimed at minimizing net power costs and the Company is unable to respond to short- or even intermediate-term changes in markets. While the cost of the commodity is locked in for future periods, the value of the contracts is constantly being evaluated and adjusted based on the most recent forward price estimates.

Q. Has the Company demonstrated that hedging in future years provides the best protection from volatility?

A. There has been no information presented to indicate that the current level of hedging has been determined to provide the best protection for the Company or for ratepayers. The percentage of hedging on future years has been established to reduce the fluctuation in net power costs for the test period that will likely be used in the next rate case. There has been no information provided to indicate that the amount of hedging in future years has been evaluated to determine the optimal amount.

Q. Has the Company demonstrated that the current hedging program will result in the least cost to the Company and to ratepayers?

A. No. The Company has clearly stated in policy that the current strategy will not result in the lowest cost. Since hedging comes at a cost, buying on the market would provide a lower cost strategy, albeit, at a higher level of price volatility. This lack of flexibility can mean missed opportunities to benefit ratepayers.

Q. What is hedging and how is it used at the Company?

A. Hedging is similar to purchasing insurance to protect against unforeseen circumstances. In the case of natural gas, the utility purchases various contractual arrangements or financial instruments to secure the future price of the commodity. The Company has been using hedging products to reduce risk and volatility for several years and has a well established energy and trading department. The revenue or expenses for these various hedging products, including the change in value based on the updated forward price curve, are included in the net power cost and are ultimately included in rates. Determining the updated market value of these contracts based on the current forward price curve represents a price estimate at a particular point in time. The value of these contracts will change as the forward price of the commodity moves up or down. Any hedging program should be cost effective and should not add unnecessary expense to the total fuel costs paid by ratepayers. As described in the May 18, 2009 technical conference, the cost/benefit ratio of a hedging program is expected to average zero.[9]

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[redacted] END CONFIDENTIAL

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 was supplied from natural gas generation resources in 2009. In determining whether to dispatch its natural gas-fired

[9] Commodity Price Risk Management Presentation to Utah Public Service Commission Technical Conference, May 18, 2009 p. 5.
[10] PacifiCorp, Exhibit 10 – Commodity Price Exposure Hedge Program, p 2, Item 7.

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.[11] The decision to dispatch the natural gas facilities is affected by the volatility of the price of natural gas. In response to DPU data request 4.12, the Company provided the forward price curves as of December 31, 2009 and March 31, 2010. Each forecast represents a specific period of time and the best information that was then currently available. While these two forecasts are only three months apart, the forecast for April 2010 delivery showed a price reduction of BEGIN CONFIDENTIAL [redacted][12] [redacted]

[redacted]

END CONFIDENTIAL

Q. Has the Company indicated if the current hedging program would be changed or remain the same if the ECAM is approved?

A. Yes. In DPU Data Request 4.1 the Division asked the following:

[11] PacifiCorp, 2009 10-K Report, p. 10.
[12] Response to DPU Data Request 4.12.

> What is the functional relationship between the proposed ECAM and the Company's current hedging policies? Why are both these processes needed to minimize risk of being exposed to volatile fuel or other power costs? Describe in detail how the Company's current hedging policies will change with the establishment of an ECAM.
>
> Response to DPU Data Request 4.1
> The Company's current hedging program is independent of the proposed ECAM. The current hedging program is designed to reduce the Company's exposure to wholesale market price volatility impact to net power costs. The hedges available to the Company do not completely match the Company's exposure; therefore, the Company will continue to have some exposure. While the Company plans to continually improve its hedge program, there are no plans to change the hedge program due to the establishment of an ECAM

Q. Are there other factors that can have an impact on the hedging program?

A. Yes. The projected load forecasts can have an impact on the effectiveness of the hedging program. The supplemental testimony of Frank C. Graves identified the following:

> When deciding how much to hedge, a utility relies heavily on forecasting (esp. of untraded factors that influence its total costs) to estimate how much fuel and power it will need to procure in future months and years. Forward gas prices are observable and can be locked in, but forward demands for retail power can only be estimated. Errors in forecasting and estimation can reduce the value of hedging and impose additional costs to a utility which might otherwise be fully hedged absent the load uncertainty.[13]

The importance of having accuracy in the projected load forecast was addressed by the Company in response to OCS Data request 2.143.

> Having the "right hedges" for the wrong load will impose costs and reduce the net value of hedging. Likewise, having the wrong hedges for the right load will also be costly. For instance, even if the load forecast is accurate, if correlations between different factors driving prices are estimated with error, the hedges may cover more or less risk than perceived.

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

[13] 09-035-15 Frank C. Graves Supplemental ECAM Testimony, p. 39, Line 797.

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 declining price can change the market value of the contract which could require the Company to make a cash collateral payment to the counterparty. Additional collateral requirements on derivative contracts totaled $82 million in 2008 and $23 million in 2009.[14]

Financial hedges for electricity function in a similar manner but move in the opposite direction to the gas hedges. Since the Company is acting as the seller, it is seeking to protect itself from low wholesale electricity prices. In the case of electric contracts, if the current market price in higher than the contract price at the expiration date, the Company is required to pay the counterparty the difference between the market and the contract price.

In its overall hedging strategy, the Company relies on the correlation between the prices of natural gas and electricity to offset each other and create a natural hedge. That is, if it realizes significant losses from its natural gas hedges, it expects those losses to be substantially offset by gains realized from its electricity hedges. This strategy of an offset assumes that exposure to the two commodities is roughly equivalent. As I will explain below, that assumption is likely to be compromised into the future.

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. Based on the December 31, 2009 10-K report,

[14] PacifiCorp 10K Report, December 31, 2009.

the Company reported that it had economically hedged 95% of its financial exposure and 53% of its forecasted physical exposure for 2010, 87% of the financial and 26% of its physical exposure for 2011.[15] Table 1 is a summary of the natural gas hedging percentages by year based on the Company's 10-K reports. The Company has determined that it will only report hedging activity for the next two years in the 10-K report even if there are contracts that extend beyond that time period.

PacifiCorp Natural Gas Hedging

Based on information provided in the 10-K reports

As of	Type	2007	2008	2009	2010	2011
12/31/2006	Physical	100%	89%			
	Financial	100%	100%			
12/31/2007	Physical		82%	61%		
	Financial		97%	84%		
12/31/2008	Physical			64%	48%	
	Financial			94%	85%	
12/31/2009	Physical				53%	26%
	Financial				95%	87%

Table 1

There is some confusion concerning the actual percentages of physical and financial hedging. Both the physical and financial contracts are considered derivative contracts and are included together for reporting purposes. Based on the information presented in Exhibit 1, it is clear that the level of hedging is different between the physical and financial hedges. The actual percentages of the physical and financial hedging for electricity are not disclosed in the annual reports but have been determined through data requests. The actual percentage of electric hedging as of year-end 2009 was significantly different than percentages identified above. Because of the different nature of the contracts and the difference in maturity, the natural gas physical and financial hedges should be examined and reviewed separately. The electric contracts should also be separated by the physical and financial characteristics and reported separately.

[15] 2009 PacifiCorp 10-K, p. 10.

Q. Does the Company currently have guidelines for the amount of financial hedging allowed in future years?

A. Yes. The guidelines are very clearly identified in the Company's Commercial and Trading Front Office Procedures and Practices manual. A summary of the hedging targets is included as Chart 1 below. BEGIN CONFIDENTIAL [redacted][16]

END CONFIDENTIAL

Q. Has the Company indicated any changes to the hedging program?

[16] Response to DPU Data request 4.4.

A. Yes. Based on the technical conference that was held May 25, 2010, the new guidelines BEGIN CONFIDENTIAL [redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

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Q. Have you been able to determine anything else from the new guidelines?

A. Yes. Based on the way the program is designed and the wide tolerance, there is only a remote possibility that the Company will ever be in an over-hedged position. The Company has indicated that if they were to become over-hedged they have no guidelines and no mechanism to get out of or unwind any of the transactions. The most likely outcome would be to wait and see if market conditions changed to return the program to the predetermined tolerance levels.

Q. Can you provide some examples of what other utilities are doing with their hedging program.

A. Yes. The **Nevada** Commission has recently reviewed the proposals for Sierra Pacific Power (SPPC) and Nevada Power (NPC). Pursuant to NAC 704.9061 the "Energy Supply Plan" establishes the parameters of an energy supply portfolio for the three year period covered by its Action Plan. The objective of the Energy Plan is to minimize the cost of supply, minimize price volatility and maximize the reliability of energy.[17] Under the current proposal, the Company provided the Commission with 20 different hedging alternatives. The suggested natural gas hedging program for 2010 called for 50% open and 50% hedged fixed price products. The proposed plan called for the Company to begin procuring the financial hedges four seasons prior to delivery instead of the current practice of beginning three seasons ahead. After review of the proposed plan and the other 19 alternatives, Staff determined that the Company had not demonstrated that the proposed plan was prudent and recommended that the Commission order SPPC and NPC to adopt an unhedged plan (i.e. buy all of its gas at unhedged market prices).[18] They further recommended that SPPC and NPC suspend all

[17] Public Utilities Commission of Nevada, Docket No. 09-07003, Volume 3 of 6 Energy Supply Plan, p. 4.
[18] Public Utilities Commission of Nevada, Docket No. 09-07003 & 09-09001, Direct Testimony of Yasuji Otsuka, PhD, p 2.

hedging activities until the Commission approves a new hedge plan as part of the Energy Supply Plan expected in November 2010.

The **Alaska** Commission is currently studying this issue. In the April 12, 2010 presentation, Michael Getting, Senior Partner with RiskCentrix, LLC identified the characteristics of the best mitigation programs and identified 5 features that should be included.

1. Establish tolerances for upside customer bills, potential hedge losses and for a contingent options budget.
2. Assess the rate of response required to mitigate intolerable cost outcomes. (Hedge risk losses on market reversals)
3. Assess potential losses and collateral at that response rate.
4. Attenuate the necessary response rate (& loss potential); plan to limit the transient close-in risk by placing preemptive early hedges
5. Plan contingent strategies to mitigate losses in extreme conditions.

For the Alaska utility, Mr. Getting recommended hedging 25% beginning 2 to 3 years in advance and use options to manage the extreme price fluctuations determined by the loss tolerance.[19]

Additional State specific information is available in the Blue Ridge Consulting Services report.[20] In summary, the following is a brief description of what some Commissions are doing with their utility hedging programs.

Colorado - Established a Gas Price Volatility Mitigation Plan in 2004. Company specific details are confidential; however, hedging costs are included in the commodity adjustment. **Florida** – Utilities can hedge up to 100% of requirements using financial instruments and can hedge up to 48 months in advance. **Kentucky** – Financial and physical hedging is allowed with maturities up to 36 months in advance. **Wyoming** – Docket No. 20000-315-EP-08 requires Rocky Mountain Power to meet with the Office of Consumer Advocate (OCA) to review gas purchasing and hedging policies. **Washington** – The Commission has not

[19] Regulatory Commission of Alaska, Risk Management Prudence Standards, March 31, 2010.
[20] Docket No. 09-035-23, Net Power Cost Evaluation, Blue Ridge Consulting Services, Inc., October 7, 2009.

established a range or provided specific guidance for hedging levels or durations. The National Regulatory Research Institute also published a report that identified some of the actions currently being taken by other utility companies and commissions.[21]

Q. Are you aware of other groups that are looking at derivatives and hedging?

A. Yes. Derivatives used by utilities are receiving attention in many areas and are the focus of published reports and training seminars.[22] With the recent price volatility of natural gas and the national attention given to derivatives, this issue is being reviewed by other commissions and by consumers. On March 31, 2010, Michael Getting presented "Risk Management Prudence Standards" to the Regulatory Commission of Alaska.[23] The Regulatory Operations Staff of the Public Utilities Commission of Nevada filed testimony on March 4, 2010 concerning the proposed hedging plan for Pacific Power and Nevada Power.[24] On February 15, 2010, Michael Getting presented "Prudence Standards for Utility Hedging" at the NARUC Winter Committee Meetings. In January 2009, Vantage Consulting and its subcontractor Pace Global Energy Services completed an analysis of gas hedging for the board of the New Jersey Gas Distribution Companies.[25] In February 2009, the NARUC Board of Directors adopted a resolution addressing excessive speculation in the natural gas markets.[26] In February 2009, the Consumer Advocate Division of the West Virginia Public Service Commission requested a general investigation into natural gas hedging practices.[27] In June 2008, NRRI published "Gas Supply Planning and Procurement: A Comprehensive Regulatory Approach." In addition to these events, changes in the accounting procedures for

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[21] National Regulatory Research Institute, Gas Supply Planning and Procurement: A Comprehensive Regulatory Approach, June 2008.

[22] "Prudence Standards for Utility Hedging" NARUC Winter Committee Meetings, Michael Gettings, February 15, 2010. "Aligning a Utility's Interests with the Public Interest in Cost-Effective Purchased Power Transactions," National Regulatory Research Institute, David Magnus Boonin, April 6, 2009. "Energy Portfolio Management: Tools & Resources for State Public Utility Commissions," NARUC, October 2006.

[23] "Risk Management Prudence Standards" Regulatory Commission of Alaska, March 31, 2010. Sierra Pacific Power Company and Nevada Power Company Proposed Natural Gas Hedging Plan for 2010, Public Service Commission of Nevada, Docket No. 09-07003 & Docket No. 09-09001. March 4, 2010.

[24] Public Utilities Commission of Nevada, Docket No. 09-07003 & 09-09001, Direct Testimony of Yasuji Otsuka, PhD.

[25] Vantage Consulting, Inc. "Analysis Of The Gas Purchasing Practices And Hedging Strategies Of The New Jersey Major Gas Distribution Companies Final Report." 15 January 2009.

[26] www.naruc.org/Resolutions/CA Resolution Addressing Excessive Speculation in Natural Gas Markets.

[27] Public Service Commission of West Virginia, Case No. 09-0148-G-PC.

reporting hedging activities have recently been implemented and legislation is currently being debated in Congress as part of the financial-overhaul package. While it is uncertain what the final bill will contain or how it will affect utilities, new rules concerning derivatives could become law as early as July 2010.

Q. Does the Company do any other type of hedging for Natural Gas?

A. The Company has indicated that the strong long-term correlation between movements in natural gas and electricity prices creates an internal hedge, with an increase in natural gas costs offset by an increase in power revenue. This internal hedge and correlation assumes that the Company will maintain the current position with excess power to sell. The Division is concerned with this assumption since the Company has indicated that they will not be able to meet the energy demand without additional market purchases within the next few years.

Q. Can you provide an example of how the correlation and change in the forward price curve can have an impact on the net power cost?

A. Yes. There is a correlation between the price of natural gas and the price of electricity, however, there is not a dollar for dollar matching price movement. A comparison of several grid runs has identified the significant price fluctuation of the swap contracts. As part of the 2008 rate case, Docket No. 08-035-38, the Company provided an estimate for net power cost for the test year ending December 2009, pricing these contracts using the forward price curve at that time. This estimate dated November 14, 2008 was submitted as part of the surrebuttal testimony of Mr. Greg Duval. The second grid from the same rate case is dated February 6, 2009, and was submitted in answer to UIEC data request 2.1(1). The third grid run is from the 2009 rate case and has a test period ending June 2010. This estimate includes the last 6 months of 2009 and is dated November 4, 2009.

	Gas Swaps	Electric Swaps	Net
11/14/08	(80,070,048)	37,692,263	(42,377,785)[28]
2/06/09	(155,263,403)	83,857,059	(71,406,344)[29]

[28] Docket No. 08-035-38, CY2009 NPC Study (GOLD) 2008 11 14.

11/04/09	(167,137,440)	187,666,835	20,529,395[30]

Recognizing that the third estimate is a different test period, it is important to see the change in value and the impact that these contracts can have on net power cost. In the 2008 case, the net result of swaps was estimated to increase net power cost by $71.4 million. In the 2009 case, net power costs were reduced by $20.5 million due to the price fluctuation in the swap contracts.

Q. How will additional purchases change the hedging strategy?

A. With the projected increase in demand, the Company will see a reduction in the amount of electricity available for sale and is projected to require additional market purchases of electricity. The change from having excess power to sell to requiring additional power purchases could reduce the offsetting effects of gas and electricity hedges, as, 1) there will be substantially more exposure to natural gas risk than to electricity, and 2) it will no longer be appropriate for the Company to hedge electricity as a seller. The latter means that the ongoing correlation between gas and electricity prices would magnify, rather than offset, hedging losses in one commodity. This would affect the volatility of net power costs. The current hedging program assumes that the current relationship between natural gas and electric hedging volumes will continue even though conditions will likely change before the maturity of the contracts. Current projections indicate that without additional generation resources the Company will need to purchase additional power in less than 48 months, thus mooting its current hedge position as a net seller of electricity. In addition, the Hermiston natural gas contract was structured as a fixed price long term contract and represents 28% of the total natural gas volume. This contract is scheduled to expire in June 2011, which could also affect the current relationship of gas to electricity within net power costs.

Q. Can you review the performance of the current natural gas hedging program?

[29] Docket No. 08-035-38, UAE 3.1-1 Final (OFPC1208) 2009 02 06.
[30] Docket No. 09-035-23, UT GRC REB NPC – June 2010 GOLD 2009 11 04.

A. Yes. Chart 2 compares the Opal spot price to the Henry Hub spot price from January 2004 through February 2010. This has been included to show the relationship between these two index prices. As can be seen below the Opal price has historically been below Henry Hub although currently the two are very close. Opal has been used to compare the price paid for the PacifiCorp contracts since it is a better representation of prices in the intermountain area.

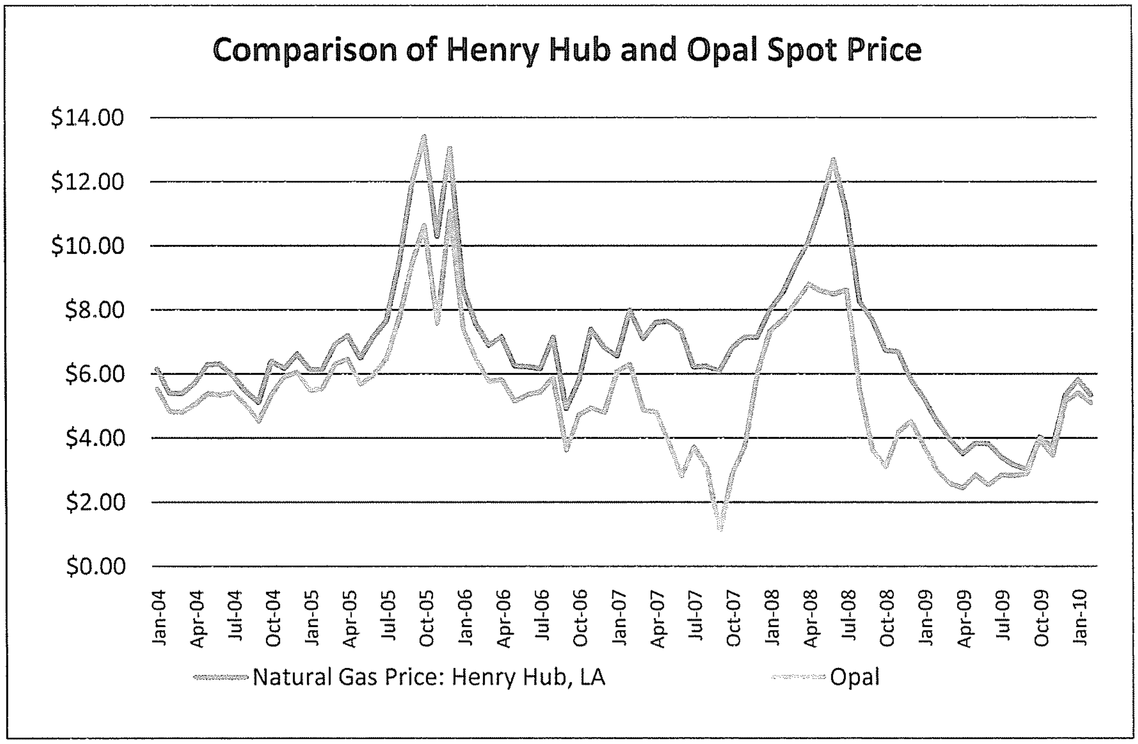

Chart 2

In response to data request, the Company provide the total cost paid for natural gas including the hedging costs.[31] Chart 3 compares the Company's actual natural gas cost to the spot market Opal price. The total price for natural gas including the hedging cost is used to evaluate the hedging program compared to purchasing gas at spot price. The chart includes linear trend lines to show the direction of the price change over the time period. While the spot price for Opal has been trending downward since 2004 the PacifiCorp price has been trending higher due to the long term nature of the contracts. The Opal spot price has been more volatile but the Company price has also shown

[31] Docket 09-035-21, DPU Data Request 4.10 and 4.11.

fluctuation. As noted above, in a decreasing price environment the Company may be required to pay the counterparty for the difference between the negotiated contract price and the current market price and may require additional cash collateral payment.

The Company hedging program has worked to reduce natural gas price volatility. From 2004 through April 2007 the Company was able to pay less than the spot price, however, since July 2008 the Company and rate payers have paid more than the spot price. While the Division is aware that the Company will not always be able to purchase at rates below the spot price, there should be some provisions to manage the risk to the Company and rate payers if prices fall.

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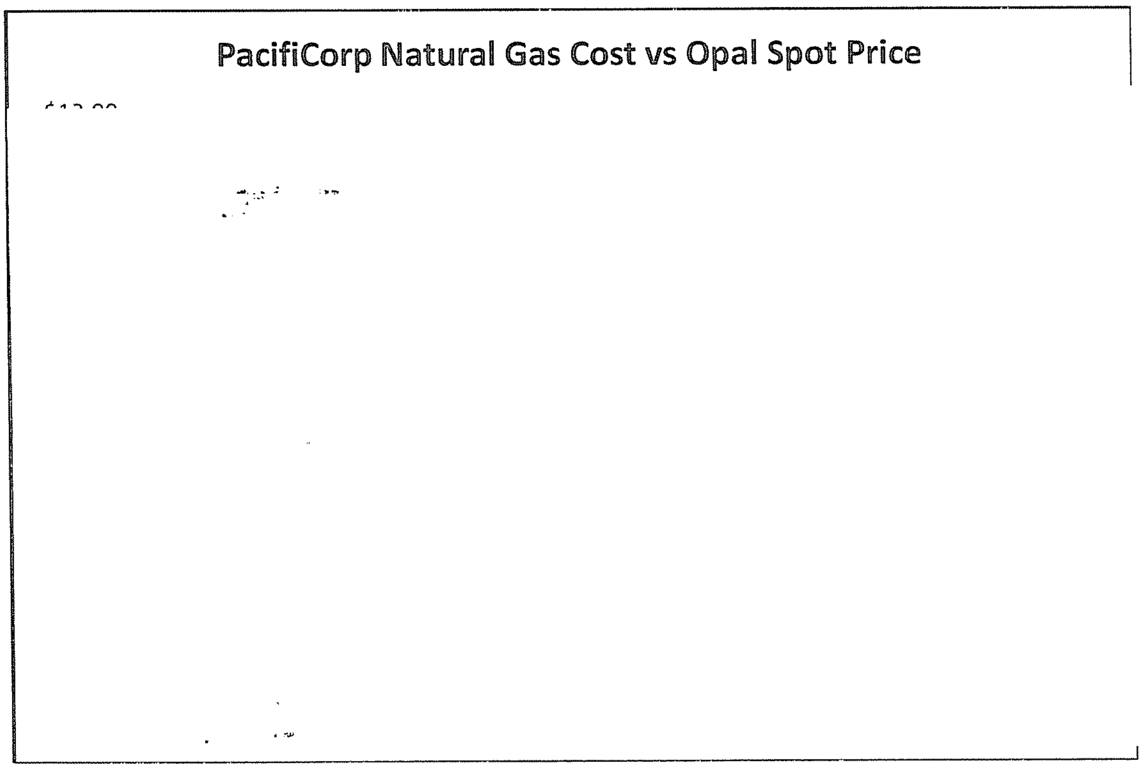

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Q. Has there been a significant change in gas volumes during this same time period?

A. The Company provided the actual natural gas volume by month in response to data request 5.1. In looking at the total volume consumed over the last 3 years, there has been monthly fluctuation with a slight annual increase. BEGIN CONFIDENTIAL [redacted]

[redacted]

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Q. How does the historical price paid for natural gas compare to the forward price curve?

[32] Docket 09-035-21, DPU Data Requests 4.10 and 4.11.

A. Chart 5 includes the historical information for the Company and the Opal spot price from Chart 3 with the projected forward price curve as of March 31, 2010.[33] BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL The 2010 Annual Energy Outlook includes a projection for estimated natural gas well head prices through 2035. They estimate prices to be fairly flat through 2025 and then a slight increase to approximately $7.50 in 2035. With the long term nature of the existing hedging contracts and the projected low prices in future years, it is uncertain when the price of the current hedged portfolio will be comparable to the Opal spot price.

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Q. How will the current hedging program function with the projected price of natural gas identified by the Company?

A. The current program works in a rising price environment. Since the Company is purchasing the majority of the contracts BEGIN CONFIDENTIAL [redacted] END

[33] DPU Data request 4.12.

CONFIDENTIAL it is protected from sharp price increase but is not able to take advantage of price reductions. Unforeseen circumstances like those of hurricane Katrina could cause a rapid increase in prices, however, there is a possibility that new shale gas production could increase supply and keep prices down. The Company should have a plan in place should either of these events occur.

Q. How does the price for natural gas paid by the Company compare to the prices paid by other utilities?

A. It is difficult to determine the prices paid by other utilities. I started with a review of the comparable companies used in the previous rate case and only a few of them provide a summary of their fuel costs in their annual reports. In order to provide a comparable analysis the natural gas costs I looked for those that reported the price paid per MMBtu. Table 3 below identifies 5 comparable companies and the price paid for natural gas for the past four years. The amounts for PacifiCorp have been shown both including and excluding the hedging cost. Chart 6 is the same information presented in a line graph format. This is included to show the extreme volatility of some of the other utilities compared to PacifiCorp. On a relative basis, Utah ratepayers have been paying less than others for the natural gas generation. This is partially due to the location of the PacifiCorp facilities and the availability of inexpensive gas compared to the other utilities. This price differential could change over time as new pipelines allow for greater movement of natural gas from the Rocky Mountain region.

Natural Gas Fuel Cost Average cost of delivered fuel per million British Thermal Units used for electric generation.	2006	2007	2008	2009
Alliant Energy				
Interstate Power and Light	10.45	9.21	8.18	13.31
Wisconsin Power and Light	14.28	13.86	8.64	18.53
SCANA Corporation	8.18	8.28	10.92	8.28
Excel Energy	7.28	7.60	10.09	7.36
Progress Energy	7.41	9.19	10.66	8.16
PACIFICORP *	4.02	5.41	7.28	7.16
PACIFICORP - Excluding Hedging		4.48	6.12	3.93

Table 3

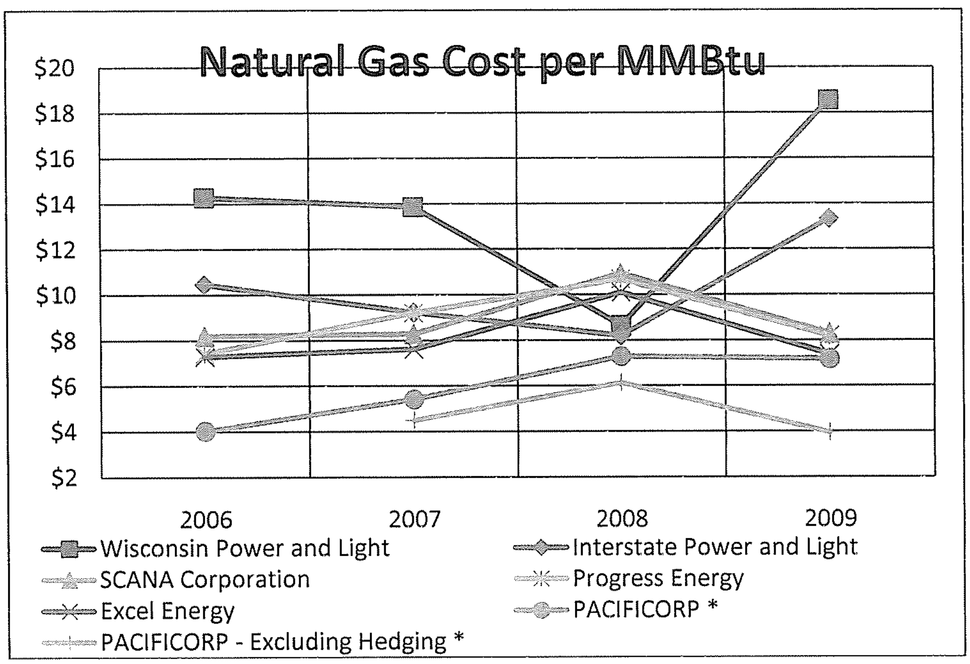

Chart 6

Q. **Have you looked at the volatility of the total fuel cost compared to other utilities?**

A. Yes. Chart 7 is a summary of the total fuel cost for the six utilities identified above. The weighted average fuel cost indicates that the Company has maintained the second lowest total fuel cost behind Excel Energy which includes low cost nuclear production. PacifiCorp has been able to maintain a low average fuel cost due to favorable long term coal contracts.

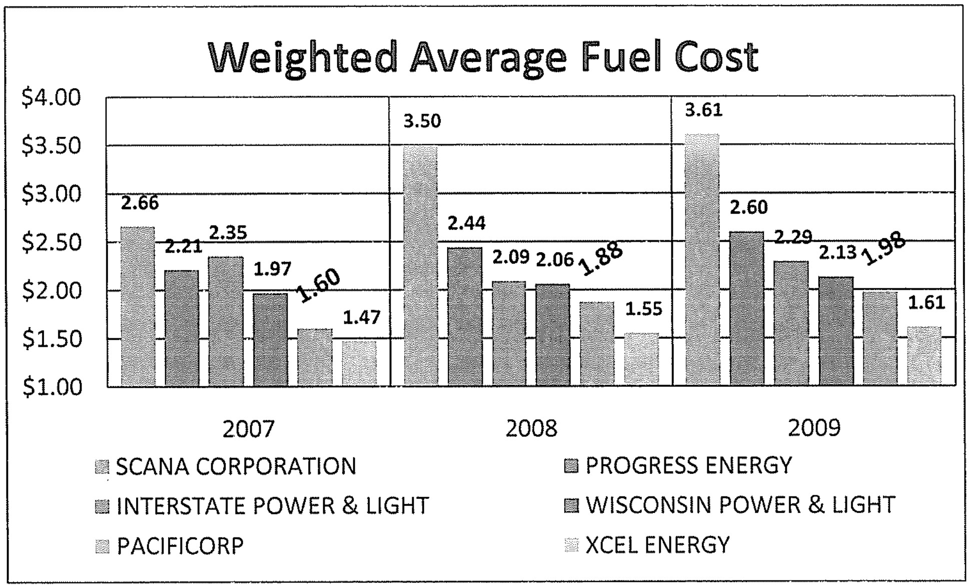

Chart 7

Q. **Has the hedging program been successful in reducing the volatility of natural gas?**

A. Based on information presented by the Company at the May 18, 2009 technical conference and in response to DPU data request 2.3 the hedging program has reduced the volatility of natural gas prices. Chart 8 is a summary by year of the hedging program excluding the Hermiston natural gas contract. The cost benefit is calculated as the contract sales price less market price to the expiration of the contract, multiplied by the contract volume. Exhibit 10 demonstrates the historical correlation between the change in price of the natural gas and electric contracts. BEGIN CONFIDENTIAL [redacted]

[redacted]

[redacted]

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Q. How does the Company summarize the purpose of its hedging program?

A. As stated in the PacifiCorp Front Office Procedures and Practices,[34] BEGIN CONFIDENTIAL

[redacted]

[redacted]

[34] PacifiCorp Energy – Commercial and Trading Front Office Procedures and Practices, Approved July 31, 2008, p. 59 (CONFIDENTIAL AND PROPRIATARY).

[redacted]

END CONFIDENTIAL

As is the case with any hedging program, some purchases will be made during periods when prices are low and some will be made when prices are high. It should be understood that current practice will not always result in the least cost.

Q. Can you summarize the specific policy issues identified at the beginning or your testimony?

A. Yes. Rate stability is an important goal, but whether PacifiCorp's current hedging strategy is appropriate has not been fully explored. The Division is concerned that the current swapping strategy has been conducted without the direct scrutiny or approval of regulators. The current guidelines have not been examined or justified as being the most advantageous to the Company or to ratepayers. Under the current program the Company has limited the risk of a price increase in natural gas but has not protected against increased costs from cash payments to counterparties or additional cash collateral requirements resulting from a drop in natural gas prices. The current practice of purchasing financial products years in advance limits the ability of the Company to take advantage of price reductions that could benefit both the Company and rate payers. This portion of the Company operation should receive careful and periodic review by the Commission.

The primary goal of the existing hedging program is to reduce the price volatility of commodities in order to stabilize prices two years in advance. The primary purpose is to stabilize net power costs in year two, since that will likely be used as the test year for future rate cases. The Company has not provided evidence that the current amount of hedging reduces the appropriate amount of risk to the Company or to ratepayers.

A key part of the Company's hedging strategy is the relationship of the gas swaps with electric swaps. The current program assumes that gas and electricity prices will always move in close tandem and that the gains and losses from one will tend to offset the other. The Division feels that the Company and the Commission should explore whether the Company should structure its overall swaps policy not as an electricity and natural gas combination, but rather as two separate strategies. This would provide protection for the Company (and ratepayers) as a natural gas consumer and as an electricity seller. For example, contracts can be structured such that the up-side risk of gas is capped, while at the same time the upside price of electricity has no ceiling. Thus, if both commodities' prices rise in tandem, the Company's cost for gas is capped, but its increased revenues from electricity would not be limited. Similar protections can be achieved through other contract structured with options and bands. This permits both ratepayer protection against rising gas costs or falling electricity market prices, and the opportunity for ratepayers to benefit from falling gas costs and rising electricity market prices. However, as discussed above, when the Company ceases to be a net seller of power, the hedging strategies will necessarily need to be decoupled.

Q. Do you have specific recommendations for the Company and the Commission?

A. Yes. The Commission should direct the Company to complete an analysis and review of specific investment vehicles currently available such as options, caps, collars and their associated cost. These products could be incorporated into the existing hedging program without a significant change and would allow greater flexibility in a falling price environment. As part of this analysis the Company should prepare a hedging decision protocol and when the use of options would be appropriate to incorporate into the current program. The use of options is suggested in published studies as part of a comprehensive risk mitigation plan.[35]

Consistent with the recommendations identified by Pace, Blue Ridge and Risk Centrix, the Division would recommend that the Company look at the limited use of options and contracts with price banding. By implementing the use of various products the specific price movement would be limited to a predetermined variance range specified in the contract. The use of options should be triggered by a predetermined relationship between the of the current prices to the forward price curve. We also recommend that the Company be required to analyze the implications of a more-varied hedging portfolios that include combinations of long-term, short-term, and unhedged positions.

The use of options could be limited to a certain percentage of the long-term gas contracts using a zero cost or costless collars. This combines the sale of a call option and the purchase of a put option and would not create additional cost for the Company other than transaction costs. Under this program the option premium collected from the sale of the call option with a higher strike price (capped sale price) will fund the purchase of a put option with a lower strike price (capped purchase price). While the options portion of the hedging program may be used on a limited basis, it will provide guidance and direction for the Company and reduce the risk that the associated costs may not be allowed. This would also reduce second guessing by other parties. As part of this process, the Company should prepare a cost estimate and annual budget for the use of options. The budget amount could be a variable amount based on the volatility of the forward price curve. The guidelines for the use of options should be reviewed by the Commission in advance of implementation as part of the total energy management review

[35] A Prescription for Regulatory Agreements Regarding Energy Commodity Price Risk Mitigation, Mike Getting, Pace, with contributions by Ken Costello of NRRI and Scott Scholten of Pace, July 18, 2008.

Q. You listed three key questions at the beginning of your discussion on hedging. How does the Division answer those questions and what additional recommendations arise from those answers?

A. My first question was, "Should the Company continue to pursue its hedging strategy without any overt guidance or requirements from the Commission about what its hedging goals should be or what hedging strategies to pursue?" The Division feels that because of the large amount of dollars that the Company's hedging practices involve, and because of the profound implications that hedging can have for ultimate customer rates and the stability of rates, that the Commission should provide the Company explicit guidance regarding the kind of hedging strategy that it feels is appropriate to pursue.

Q. Can't questions about hedging be pursued in a rate case by interested parties?

A. Examining hedging practices on a *post hoc* basis has proven to be difficult. The Company's hedging practices are complex and involve literally tens of thousands of transctions each year. Moreover, with most of the existing contracts fixed for two years or longer, the Company does not have the ability to quickly change course after those contracts have been entered. To make an after-the-fact prudence assessment or disallowance– especially in the absence of Commission guidance – would be an exercise in highly subjective second guessing. It could also be unnecessarily damaging to the Company. Having clear guidance on hedging goals and strategies would assist the Company in avoiding such second guessing and would allow for all parties to have a standard upon which to assess the Company's practices when rate cases do occur.

Q. How does the Division approach your second question, namely, "What is the goal of hedging? Should the goal give priority to cost stability (on the existing extreme) or to cost minimization (on the other extreme) – i.e. no hedging, or is there an appropriate middle ground that strikes a compromise between stability and cost."?

A. From my testimony above, it should be apparent that the Division believes that the Company has placed too much emphasis on cost stabilization, which likely has resulted in missed opportunities from the recent declines in gas prices and therefore higher rates to customers.

We do not, however, feel that cost minimization should be the only goal either. In theory, the lowest prices are achieved wholly through short-term market purchases. While Nevada Commission staff have recently recommended such as approach, the Division feels that such a goal would lead to undesirable rate volatility, especially if an ECAM were to be adopted. The Division believes that an appropriate goal of hedging for Utah would be seek to limit upside rate risk, while also leaving open the possibility of taking advantage of commodity prices declines. Such a goal can be achieved through either of two methods: 1) A mix of long, short, and unhedged positions – a more balanced portfolio of exposure to short-term volatility that allows some price declines (and increases) to be passed through to ratepayers; or 2) Use of contracts involving options, caps, and price collars that, for a small price premium, permit contract holders to cap upside risk while also allowing for response to downward price movement. At this time, the Division does not have a position on which approach is best in achieving our stated goal, but would look toward the results of a Commission-ordered analysis such as we have recommended above to help guide future decisions.

Q. Please then answer your third question: "What kind of guidance would it be appropriate for the Commission to provide if it chose to do so?"

A. Through our research in this and other dockets, we are aware that Commissions have taken a wide range of approaches, from extremely prescriptive approaches that include, for example, specific mixes of hedging instruments and specific time horizons, to very general suggestions. (See for example DPU Exhibit 3.8 to Michael J. McGarry, Sr. Direct Testimony in Docket 09-035-23.) The Division does not feel that a rigidly prescriptive set of guidelines would be appropriate, especially given the relative lack of experience in examining hedging that the Utah regulators currently possess. Rather, we recommend that the Commission, in this Docket, provide a clearly stated goal or set of goals that it expects PacifiCorp's hedging program to achieve. The Commission may also provide general guidance on hedging strategy, such as requiring the future use of options or requiring a greater variety of instruments, consistent with the stated goals.

Q. Under the Division's recommendation, would this Docket be the end of the Commission's scrutiny of hedging?

A. No. In addition to asking for guidance in this Docket, the Division recommends that the Commission establish a biennial process for reviewing and approving the Company's hedging practices.

Q. How would that process work?

A. Every two years the Company would be required to file a hedging plan with the Commission. This plan should include the current hedging goals and strategies for both natural gas and electricity along with estimates for market purchases over the next four years and would be filed by March 31 of each odd-numbered year beginning in 2011. This will coincide with the IRP filing date requirements and will help to align the hedging guidelines with the IRP and the Business Plan. Upon filing of the plan, the Commission would open a docket in which interested parties would be able to file direct and responsive testimony relating to the plan. Analysis of the plan would center upon whether it conforms with the goals and/or strategies as required by the Commission in previous orders (from first this and then succeeding hedging dockets), as well as the reasonableness of the plan as a means of achieving the required goals of the program. Parties would also be able to file testimony as to whether the Commission's requirements should be maintained or modified. At the end of the process, the Commission would either approve or disapprove of the plan. Approval would allow the Company to move forward in executing its plan and, so long as it stayed within the plan in its hedging practices, no party would be able to challenge those practices for reasonableness or prudence. (Note: This would not preclude a prudence challenge based upon costs of conducting the hedging program.) If the Commission does not approve the plan, the Company would be directed to submit a new plan that confirms with Commission requirements.

Q. Would this impose a major burden upon the Company?

A. The Division acknowledges that the imposition of any new regulatory process upon the Company creates some degree of burden. However, we believe that the creation of such a process has definite advantages. One is that it protects the Company from "second guessing" about its strategy and potential prudence challenges if a party disagrees with them. Two, the process allows for input from all interested parties. The Company's current hedging practices are very opaque but it is our hope that this process will allow for future collaboration between the Company and the parties in establishing each biennial plan.

Q. What if the Company receives an order from another state's commission that somehow contradicts either an approved plan or the Utah Commission's guidance?

A. The Division believes that the process it is suggesting would be flexible enough to deal with such instances. In filing its annual plan, the Company would certainly want to bring any contradiction to the Commission's attention and ask that the Commission either alter its guidance or to allow the Company flexibility to meet both sets of requirements. Moreover, we would point out that the possibility of such contradiction exists in many areas (such as interstate allocations) and can be dealt with accordingly.

Q. What if the Company sees an opportunity to benefit ratepayers or otherwise meet the Commission's goals by acting beyond or outside of the plan?

A. In anticipation of such instances, we recommend that the Commission allow for the Company to file for permission to deviate from the plan when it makes sense to do so. Such filings should be handled on an expedited basis.

Q. Does this conclude your testimony?

A. Yes