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I. INTRODUCTION, QUALIFICATIONS, ASSIGNMENT

Q. Please state your name, employer, and address.

A. My name is Frank C. Graves. I am a Principal at *The Brattle Group*, an economic and management consulting firm located at 44 Brattle Street, Cambridge, MA, 02138.

Q. What is the purpose of your testimony?

A. I have been asked by Rocky Mountain Power ("Rocky Mountain Power" or "the Company")[1] to provide supplemental direct testimony in response to certain issues raised by the Utah Public Service Commission's June 18, 2009 Procedural Order in this docket. Specifically, I have been asked to evaluate the need for, and benefits from, the proposed Energy Cost Adjustment Mechanism (ECAM) proposed by Rocky Mountain Power for recovery of its Net Power Costs (NPC). I therefore provide a description of the circumstances that warrant the ECAM, including the uncertainty in, and uncontrollable nature of, NPC. Naturally, some components of NPC are quite volatile, and the Utah Public Service Commission has asked whether these risks are manageable and what alternatives are available to manage them. To address these issues, I have evaluated the risk management capabilities and practices of Rocky Mountain Power to determine how they can contribute to managing the cost and quantity risks that will be recovered in the ECAM. In the course of explaining my findings, I will also review some of the basic principles of risk measurement and management, and I will explain the

[1] Rocky Mountain Power is a division of PacifiCorp. For simplicity, however, references in this testimony to Rocky Mountain Power or the Company at times denote PacifiCorp or another division, PacifiCorp Energy, unless in figures or charts a specific publication source cites to the company name.

practical limitations and tradeoffs involved in hedging to reduce power supply risks. I also explain why hedging by itself is not a viable alternative to the proposed ECAM.

Q. What are your qualifications for the analyses you present?

A. I have been involved in consulting to electric utilities on resource planning and other strategic matters for over 25 years. Portfolio-based resource planning became a particular focus of my support for the industry in the mid-1990s, when federal and state restructuring initiatives put a heightened emphasis on the value and risk of generation assets and wholesale market contracts. Since then, I have been extensively involved in generation planning and in the design of procurement and cost-recovery mechanisms for utilities seeking to cover the costs of serving their residential, commercial and industrial retail customers with managed portfolios or outsourcing strategies. I have testified numerous times on this issue and the related problems of price forecasting, risk management, and service design. My professional and education qualifications are attached as Exhibit RMP___(FCG-1S).

Q. How is your testimony organized?

A. In Section II, I present a short summary of my analysis and the key findings. The balance of the testimony then presents more details and a more thorough explanation of the economic foundations for the key conclusions. In Section III, I describe the nature of the cost risks faced by Rocky Mountain Power (and other electric utilities) from exposure to wholesale market fuel and power prices and their associated volatility, uncertain demands and plant performance, forecasting difficulties, and other factors. In Section IV, I review basic concepts in risk management for electric utilities with retail load obligations. In Section V, I describe the limits on Rocky Mountain Power's ability to control its ECAM cost risk, even under aggressive hedging policies. In Section VI, I explain the suitability of Rocky Mountain Power's risk management practices for supporting the proposed ECAM. Section VII briefly summarizes my conclusions.

II. SUMMARY OF ANALYSIS AND RESULTS

Q. What supply-cost circumstances are necessary for an energy cost adjustment mechanism to be appropriate?

A. An ECAM is attractive as a regulatory policy when a utility faces operating costs that are:

- highly uncertain due to price and volume impacts;
- largely uncontrollable and non-discretionary, once the broad elements of the physical supply portfolio have been chosen in long-term resource planning; and
- large and material to the costs of power and to the financial burden on the utility and its customers.

Q. Do these circumstances apply to the Rocky Mountain Power supply portfolio that is used to serve its customers?

A. Yes, these preconditions are clearly present, and they are probably becoming more significant. A bit more than one half of Rocky Mountain Power's Net Power Costs arises from coal, with the balance coming mostly from natural gas, net purchased power (purchased power less wholesale revenues), and transmission charges. The prices and quantities of the natural gas and net power purchases are particularly uncertain and variable over time. These resources tend to be used to serve the most weather sensitive (*i.e*. uncertain, variable) portions of daily and seasonal load. The cost of meeting these residual demand requirements have become more unpredictable in the past few years, for several reasons. First, there has been increasing reliance by Rocky Mountain Power on renewable resources, which now provide about 5 percent of total generation but are subject to substantial daily and seasonal variation in output. Second, the prices of natural gas and wholesale purchased power themselves have become more volatile in the past few years, in part due to unprecedented movements in world-wide energy prices (rising to extremes in 2007 and early 2008, and then collapsing in the wake of the financial crisis). This macroeconomic downturn has also made future demand growth more uncertain. Looking ahead a few years, it is likely there will be a CO_2 surcharge from "cap and trade" policies, and this expense could become large and volatile by itself.

Q. Are the NPC substantial enough to merit the ECAM recovery mechanism?

A. Yes, they are large and financially material. From 2005 to 2008, the NPC of Rocky Mountain Power and its affiliated distribution companies grew from around $783 million to $1.12 billion. This represents about one-third of the PacifiCorp utilities' total retail power costs ($3.4 billion in 2008). For comparison, NPC is almost three times the size of 2008 net income of $458 million. Just the increase in NPC from 2005 to 2008 of $337 million is itself almost as large as that entire 2008 net income, and it is a bit more than

PacifiCorp's 2008 interest on long term debt of $313 million.[2] Thus, unreliable recovery of these amounts could have adverse impacts on Rocky Mountain Power's financial health. Given the weakness of our financial system at this time, and the associated difficulties in raising capital, it is important to be above average in financial health.

Q. Are there other reasons why an ECAM would be helpful and timely?

A. Timely recovery of NPC will help customers receive accurate information about the economic value of power, in order to make efficient consumption decisions. This may seem like cold comfort, but in fact it can be very valuable. Eventually, customers should bear all of the costs that are prudently incurred to provide service. If this is done in a timely, incremental fashion, customers do not experience occasional, jarring rate shocks, and they have the ability to make gradual adjustments to their own consumption habits. As we begin to price carbon, and as we turn more and more to conservation and load management as alternatives to traditional central station generation, customers' ability to make responsive choices will help them save money, improve reliability, and help achieve environmental goals. From a regulatory viewpoint, putting uncontrollable costs into an ECAM (subject to their being prudently incurred) will let the focus of attention be on the harder decisions the utility can and should control, such as the long run mix of resources it relies upon and what kinds of service pricing and quality are provided.

Q. What are the alternatives to an ECAM?

A. While there are many variations and nuances to how a utility's operating costs

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2 PacifiCorp FERC Form 1, pages 114-117.

could be reviewed and recovered, there are basically only a few types of alternatives: One is the situation Rocky Mountain Power currently has, with no ECAM. Under such circumstances, the utility makes as good a forecast (or adjustment to historical costs) as is possible. If costs prove to be higher than forecast, the utility attempts to live within the operating budget implied by that forecast for as long as possible. This can lead to stresses on the utility that are absorbed through such practices as reduced or deferred maintenance, under-investment in otherwise attractive new infrastructure, the need to carry larger balances of net working capital, and perhaps a higher cost of funds (especially debt). All of these ultimately hurt customers. On the other hand, if costs should prove lower than forecast, the utility may defer going in for a rate adjustment for a long time, raising its profits and delaying a potential saving to its customers.

The next major alternative is to try to hedge the problem away. As explained in more detail in this testimony, there is much that hedging can usefully do to dampen risks and make an ECAM more effective and comfortable, but hedging cannot drive out the long term structural costs that affect the entire industry, nor is it possible to hedge very far into the future or to anticipate and cover all relevant risks. When risks are increasing, as now, it becomes important to allow recovery for actual prudent NPC after a hedging program has dampened the major exposures.

A third alternative is to target particular cost items and pass them on in a "rider" designed just for those expenses. For certain circumstances this can be attractive, such as when a new kind of environmental regulation (*e.g.*, for mercury control) is about to be introduced, and a narrow class of responses is needed. But that circumstance does not apply here. Rather, the whole suite of NPC are risky and probably becoming more so.

A fourth alternative is to out-source the entire supply obligation to a third-party, as has been done in some states (notably, New Jersey) that restructured and unbundled their retail service. This can work well especially for utilities that have divested their generation (unlike Rocky Mountain Power), but it entails a material risk premium to compensate the suppliers for covering the complex and uncertain obligations of retail service at a fixed price. Many jurisdictions are reviewing whether this premium is worthwhile.

Q. What is the role of risk management in mitigating NPC and ECAM cost variability?

A. Risk management, as I will use the term, refers to practices for:

1. forecasting and measuring the foreseeable range of uncertainty in future costs and revenues,
2. simulating how alternative supply portfolios and procurement practices (type, timing, and relative size of different kinds of wholesale contracts) could alter the range of future risks,
3. scheduling and controlling for how procurement occurs and how it is adjusted over time in order to keep the range of potential net costs within desired limits, and
4. monitoring and evaluating performance through reporting mechanisms.

While risk management is not essential for allowing an ECAM, it can be helpful and reassuring to customers as a means of keeping variance in the ECAM charges within reasonable bounds. *Risk management cannot be expected to reduce expected costs*. Risk does not simply disappear under hedging. Rather, it is transferred to some third party, or financed to smooth out cost variations over time. The proverbial saying is correct that "there is no free lunch." If a risk transfer is expected to reduce or avoid costs, then the hedging counterparty has to be incurring the corresponding increased costs, which will not occur absent fair compensation – hence no net reduction in overall expected costs.

What risk management does, instead of reducing costs, is to limit the exposure to extreme variation in costs. This makes utility financial operations more manageable at the same time as it helps customers cope with their fuel bills in a more timely, less disruptive fashion. Perhaps even more importantly, it requires continual monitoring and measuring of how the current procurement plan is likely to perform, which allows timely regulatory review of whether to modify the strategy to achieve alternative goals, or to respond to shifting market circumstances that were not contemplated when the strategy was first designed and approved.

Q. Why can't an aggressive risk management practice dampen risks so much that an ECAM is not necessary?

A. It is infeasible and impractical to eliminate all risk, for several reasons. First and foremost, the available hedges are not "complete", meaning they do not span all the possible risk factors and contingencies that could alter future needs or the opportunity cost of covering those needs. In particular, hedges are not generally available for distant time periods in the future, so the best that can be done to manage the changes in costs that arise over a long period is to gradually fold near- to mid-term hedges into the portfolio. This will not eliminate the eventual changes in cost, but it will spread their recognition over longer periods of time. Second, it is impractical to attempt to eliminate all risks, even if it were possible in principle to do so. Hedging is a time, money, and human resource-consuming activity that must be balanced against other uses of those assets and capabilities. As a result of practical tradeoffs, some items will remain unhedged and others will be simplified in forecasting and risk simulation models. This creates inevitable, but reasonably expected, estimation errors and gaps in hedging coverage. Third, hedging one risk often creates another, different kind of risk. In particular, locking in very long-term purchases or sales creates credit and collateral risks surrounding whether both parties to the transaction can and will perform, especially if market conditions shift materially after the hedges were entered. Fourth, the hedging process involves implicit assumptions that the current best estimates of risk and the relationships among key factors (*e.g*. based on past volatility or current market-implied volatilities and correlations) will in fact describe the future, so that one kind of risk can be predictably used to offset another, or so that a fair price can be set for transferring a risk to a third party. However, the world is not always so well-behaved and cooperative in fulfilling this assumption. Market parameters change in unforeseen and unforeseeable ways, invalidating prior hedged positions.

Q. Would an ECAM simply be allocating risk to customers that the utility might be in a better position to bear?

A. There is no question that an ECAM does allocate more short term variability in costs to customers, but this should not be presumed to be an undesirable result. On average, the costs to customers will be no greater with an ECAM than without; the same expected, prudent costs ought to be incurred and recoverable either way. But with an ECAM, the costs will be recognized and passed on in a more gradual, smoother way that avoids disruptive rate shocks. This provides more efficient, more timely price signals – including price reductions when NPC decreases. Rocky Mountain Power's customers enjoy the added assurance that sophisticated risk management capabilities already in place can be used to monitor the ECAM cost ranges and to adjust it over time, according to evolving preferences for how to reduce key risks

Rocky Mountain Power will not make money off of the ECAM; it will simply avoid losing money, or avoid losing liquidity, when fixed base rates might periodically be lower than actual costs. Keeping the utility financially healthy is beneficial for customers (especially now, in the wake of the financial crisis), because the coming decade is likely to entail dramatic expansion and redesign to the infrastructure of the power industry, if it is to adopt low carbon technologies, expand the transmission grid, introduce "smart grid" capabilities at the distribution level, and foster customer-site innovations in conservation and demand response.

III. ELECTRIC UTILITY OPERATING COST RISK

Q. How significant are fuel and purchased power as expense items faced by electric utilities?

A. For most utilities, fuel and net purchased power combined is the largest expense item they incur, often representing 35-45 percent of total delivered power costs per kWh. This is seen in Figure 1, below, which summarizes the fuel and net purchased power share of total electric operating revenues for those utilities which file a Form 1 Report with the Federal Energy Regulatory Commission (FERC).

Figure 1 – Fuel and Purchased Power Significance as a Utility Expense

Fuel and Purchased Power Expenses for U.S. Electric Utilities

	2002	2003	2004	2005	2006	2007	2008
Fuel and Purchased Power* ($ Billions)	55.6	59.5	62.6	75.3	84.2	89.5	100.6
Total Retail Revenues ($ Billions)	167.2	171.0	174.3	188.6	204.7	209.6	222.5
Fuel and Purchased Power as a Percentage of Total Electric Operating Revenues	33%	35%	36%	40%	41%	43%	45%

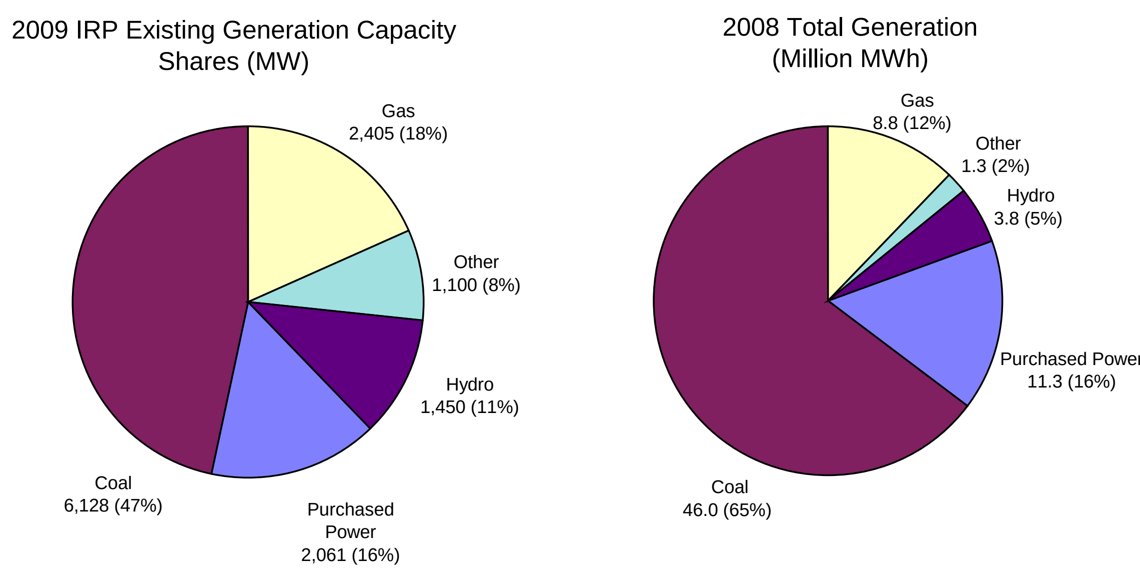
Source and Notes: FERC data, compiled by Ventyx Energy, The Velocity Suite.
*Fuel and Purchased Power is net of Sale For Resale Revenues

Rocky Mountain Power is no exception to this general pattern. Over the past five years, the Company's fuel and net purchased power have represented from 20 to 30 percent of its average cost of power.

Q. Please describe the portfolio of assets Rocky Mountain Power uses to meet its load requirements.

A. The Company currently is served by a fleet of approximately 9,700 MW of owned generation, which it uses to service a peak load of roughly 9,800 MW in 6 states, or an average load of roughly 6,800 MW. Of this load, roughly 42 percent is in Utah. The power needs of customers in all of its six state service territories are served jointly out of the same portfolio of generation assets (and, as necessary, with power purchases and sales).

Figure 2 – Resource Mix in Company Supply Portfolio



Sources and Notes: Generation capacity shares from PacifiCorp 2008 Integrated Resource Plan. Total 2008 generation data provided by PacifiCorp.

As shown in these pie charts, coal-fired generation is the largest source of capacity and electric energy for the Company, comprising 47 percent of its 2009 capacity (MW) and producing close to 2/3 of its energy (MWh) needs, with purchased power and natural gas being the next two largest components

Q. Which components of the Company's portfolio create the most cost risk for its customers?

A. Natural gas and power purchases/sales are the components responsible for much of the price and volume risk among the costs included in the proposed ECAM, for several reasons. First, they generally involve the most volatile unit costs (wholesale market prices). Second, natural gas tends to be more expensive per MMBtu and per MWh than coal, so it has more dollar-weight in the overall cost of power than its energy-weight. Third, gas and purchased power are more likely to play a marginal or balancing role against other resources with more stable or fixed costs but more uncertain performance, such as hydro and renewables that produce in varying amounts from month to month in response to weather conditions.

Q. What are the variable operating expenses associated with the Company's portfolio?

A. The variable operating expenses (almost entirely fuel costs) for these power plants and power purchases are now roughly $1 billion per year, of which the component total and per MWh (of load) costs have been as follows over the past four years:

Figure 3 – Components of PacifiCorp Net Power Costs

PacifiCorp Net Power Costs
($/MWh)

	Purchases [1]	Sales [2]	Net Purchases and Sales [3]	Coal [4]	Gas [5]	Wheeling [6]	Other [7]	Net Power Costs [8]
2005	30.49	26.95	3.54	8.18	1.13	1.56	0.08	14.49
2006	38.04	36.49	1.54	8.21	2.41	1.65	0.06	13.88
2007	18.80	19.29	-0.49	9.30	6.00	1.80	0.08	16.70
2008	14.97	16.32	-1.35	9.85	8.33	2.04	0.05	18.92

Sources and Notes:
[1] - [2], [4] - [8]: Data provided by PacifiCorp.
[3]: [1] - [2].
[8]: [3] + [4] + [5] + [6] + [7].

PacifiCorp Net Power Costs
($ Million)

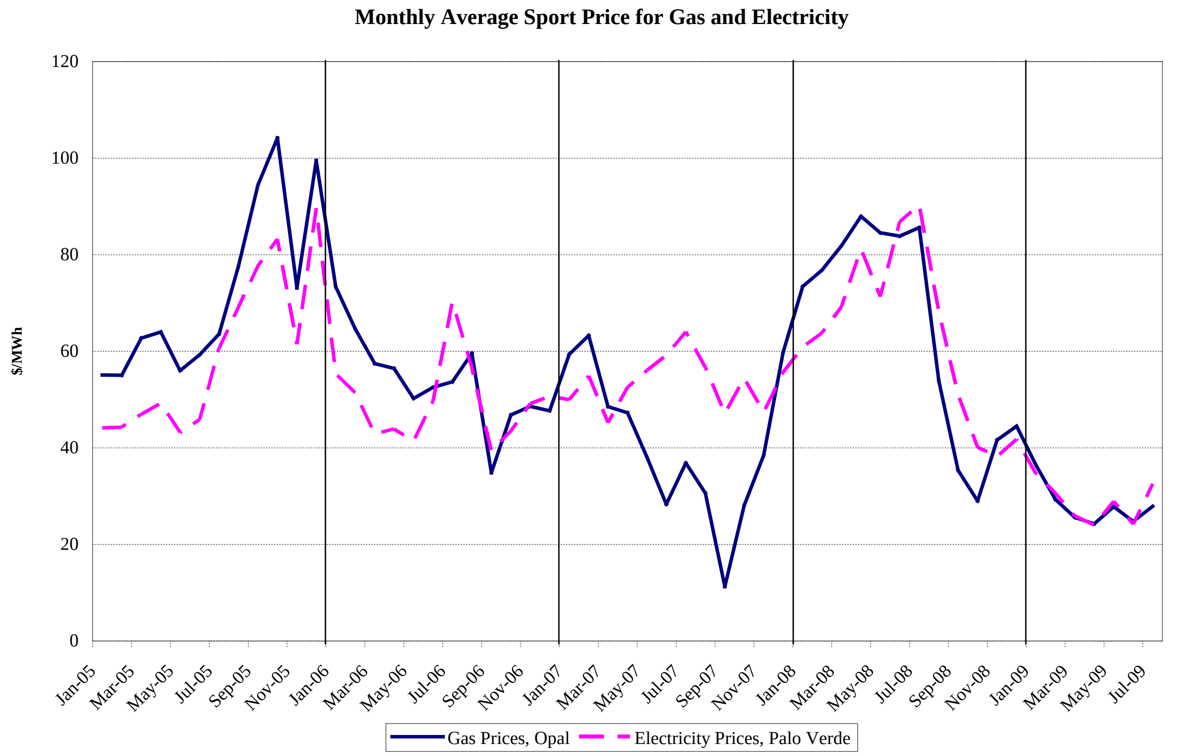
	Purchases [1]	Sales [2]	Net Purchases and Sales [3]	Coal [4]	Gas [5]	Wheeling [6]	Other [7]	Net Power Costs [8]
2005	1,647	1,456	191	442	61	84	4	783
2006	2,147	2,060	87	463	136	93	3	783
2007	1,098	1,126	-28	543	350	105	5	975
2008	886	966	-80	583	493	121	3	1,121

Sources and Notes:
[1] - [2], [4] - [8]: Data provided by PacifiCorp.
[3]: [1] - [2].
[8]: [3] + [4] + [5] + [6] + [7].

Q. Can you describe in more detail the reasons for the variability in expenses related to natural gas and power purchases/sales?

A. Yes. The total and average cost of these energy sources change considerably from year to year due to price volatility and volume uncertainty. The market price associated with natural gas and power can be quite volatile from month to month and year to year. The graph in Figure 4 depicts the historical variation in average monthly gas and wholesale electric spot prices at locations near Utah (Palo Verde for electricity, and Opal for gas).

Figure 4 – Wholesale Price Volatility for Western Gas and Power



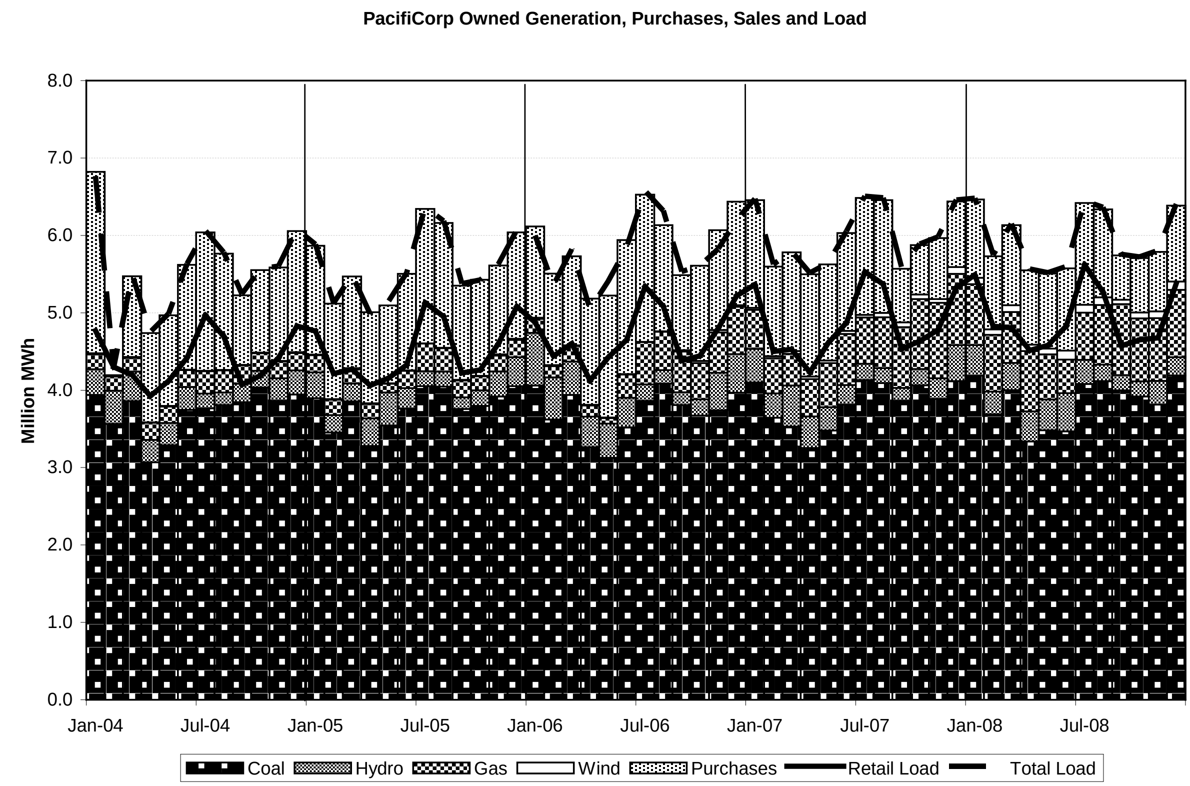
Source: Gas Prices are average of daily spot prices for Kern River, Opal from Platts Gas Daily (converted to $/MWh using an assumed heat rate of 10,000 Btu/KWh). Electricity Prices are average of day ahead spot prices for Palo Verde from IntercontinentalExchange (ICE).

Above, gas prices have been converted to an equivalent electric price per MWh by applying a heat rate around that of a natural gas peaking unit (or a steam-generating gas unit) to the raw gas prices per MMBtu. Obviously, there has been dramatic price movement over short time intervals, especially recently. In particular, natural gas prices roughly quadrupled and then fell by 2/3 within a one year period from late 2007 to late 2008. Natural gas has had an annualized volatility of around 30-50 percent per year over the last few years, meaning there is about a 1/3 chance that next year's price will be about that much higher or lower than this year's price.

Figure 4 also reveals that there is a fair degree of correlation between gas and electric prices, which is due to the fact that gas units are often "on the margin" (the last units dispatched, which are effectively setting the price of power) in the western United States. But the relation is far from perfect, or constant over time. This is particularly true in periods of reduced demand such as off-peak periods or shoulder months when natural gas resources may not be the marginal resource. So gas contractual positions can partially offset (hedge) electricity price risks, or vice versa, but there will be some significant residual risk.

This market price variability in key ECAM component costs is made more complicated by volume uncertainty over how much power and gas will be needed. Every day, utilities optimize the scheduling and dispatch of their plants to achieve the lowest possible operating cost. As a result, the relative use of the fuels shifts towards whatever fuel happens to be cheapest per MWh, subject to deliverability and reliability constraints. Production levels from weather-dependent resources like hydro and wind facilities also vary considerably, causing other more controllable generation sources to pick up the slack. And, the resource mix of available generation changes over time as assets are built or retired. Some of these effects can be seen in the graph in Figure 5 which shows the production quantities from the Company’s generation resources over time by fuel type on a monthly basis.

Figure 5 –Monthly Generation Shares and Load since 2004



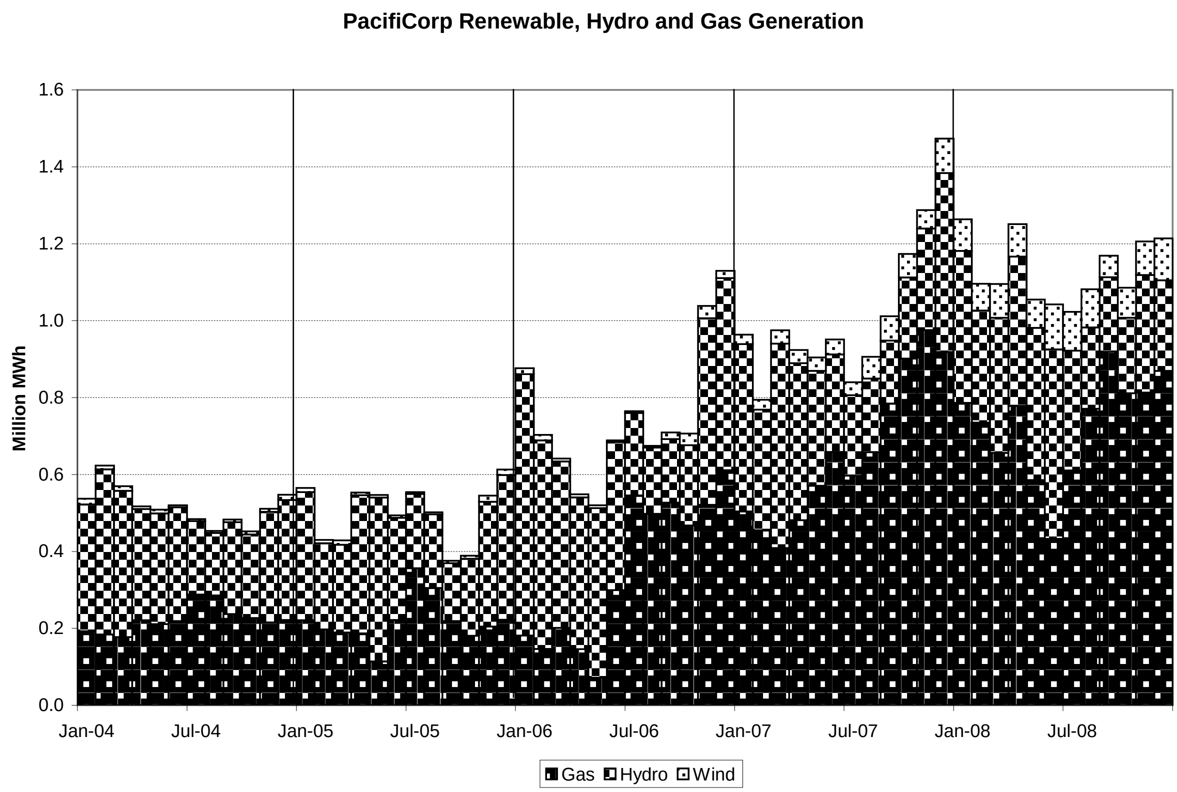
Source: Data provided by PacifiCorp.

This chart demonstrates at a monthly level that coal is the dominant source of power for the Company. The coal output changes relatively modestly from month to month, except for reductions for maintenance outages in the spring. One can also see that average monthly demands often exceed the production from these physical resources in the winter and summer months, so supplemental purchases are needed. Substantial monthly and seasonal variability in hydro (and more recently wind) output is also evident, which will usually be offset by more natural gas-fired generation or more purchases.

Figure 6 below extracts just the production of the renewables and gas-fired generation from Figure 5 over the same time frame to show how variable their output can be. Note that the natural gas output has roughly quadrupled since

2006, with much higher month to month variability recently than it displayed in the more distant past. Of course, much of this growth is due to changes in the mix of available resources. Generation from gas units increased after the company added three new gas plants totaling to 1500 MW in 2006-2008, while generation capacity from wind including PPA's increased from about 100 MW to about 1000 MW over the last few years.

Figure 6 – Renewable, Hydro and Gas Resource Generation, 2004-2008



Sources: Data provided by PacifiCorp.

Q. Are there other sources of variability in Rocky Mountain Power's NPC aside from natural gas and power purchases?

A. Yes. In addition to fuel and purchased power, there are several types of non-fuel, variable operating costs that are also quite uncertain in price and required volumes, including environmental surcharges for SO_2 (and likely CO_2 in the near future), transmission wheeling charges, and fuel transportation charges (such that the price of delivered fuels and power may vary by location). Rocky Mountain Power has price risk from holding excess allowances whose value may increase or decrease.

Q. What do you conclude from this discussion of Rocky Mountain Power's portfolio and its operating expense variability?

A. This kind and extent of variability is intrinsic to electric power supply management, and it makes it very difficult for any utility to tightly control its operating costs. This difficulty has increased in the past few years and may continue to get worse, due to increasing volatility in the fuel and power markets, stricter environmental requirements, tight credit markets, and growing capital expansion needs for the industry.

I also note that these variable operating costs share several attributes:

- They are highly uncertain,
- They are largely uncontrollable and non-discretionary, once the broad elements of the physical supply portfolio have been chosen in long-term resource planning,
- They are large and material to the costs of power and to the financial burden on the utility and its customers, and
- They contain much of the price information customers should have about the economic value of power, in order to make efficient consumption decisions.

For all of these reasons, it is reasonable that such costs be recoverable in a timely and reliable manner, subject to being prudently incurred and mitigated to the extent reasonably possible via hedging, diversification, and cost recovery smoothing over time. In fact, timely and reliable cost recovery of operating expenses has become even more important now than in the past, for at least two reasons. First, the credit crisis induced by subprime mortgages and their associated securitization(s) has made it more difficult for power market participants to raise capital on reasonable terms. Signs of unreliable cost recovery are likely to cause a strong, adverse reaction in the lending community. Second, much of the industry is facing a need for accelerated capital spending on renovated or expanded infrastructure, new environmental controls, advanced metering, and the like. These can be very valuable enhancements to the provision of electric power, but they require significant amounts of money. Their feasibility will depend on the rest of utility operations being financially secure. An ECAM can provide that kind of assurance, and risk management can help make the ECAM itself more comfortable for Rocky Mountain Power's customers. The next section of this testimony provides an overview of fuel cost hedging mechanics, opportunities, and limitations.

IV. BASIC CONCEPTS OF UTILITY SUPPLY RISK MANAGEMENT FOR RETAIL LOAD

Q. What is risk management?

A. Risk management generally refers to the suite of analytical and operational activities in which a utility measures, monitors, and reports the financial risk of its portfolio relative to its obligations and enters into transactions to manage and limit these risks.

Q. Is a risk management program a necessary component of a fuel adjustment mechanism such as the Company's proposed ECAM?

A. No. Risk management, though helpful to administering a fuel and purchased power adjustment clause such as the ECAM proposed in this proceeding, is not essential. Indeed, fuel adjustment clauses (FACs) have been in use by utilities for decades, and they were instituted before much of the technology now deemed to be central to risk management was even developed conceptually. The minimum conditions for a FAC are that the utility be facing material exposure to highly variable costs that are difficult to forecast, largely uncontrollable, and that have to be incurred (hence must be reliably compensated) in order for utility operations to continue. This is precisely the situation facing Rocky Mountain Power, as described above. However, Rocky Mountain Power is part of PacifiCorp, which has a well established and sophisticated risk management process that can be of service to limiting ECAM cost variability over time, thereby providing reassurance to Utah regulators and customers that Rocky Mountain Power can and will do what is reasonable to manage the variability of its ECAM expenses.

RISK VS. LEAST COST PLANNING

Q. Is there a difference between risk management and least cost planning?

A. There is an important distinction that must be drawn between risk management and least cost planning. Least cost planning is what occurs in IRP reviews of utility resource development alternatives. In that setting, the utility compares the costs of alternative means of supplying equivalent amounts of power to serve projected load reliably over the coming decade or more. All the compared alternatives are designed to have the same net benefits to customers, so the preferred approach can be identified as the one with the lowest cost.[3] (If the benefits were much different across the alternatives, cost alone would not be a sufficient criteria, much like one cannot meaningfully compare hamburgers to steak (or to vegetables) on a $/lb basis.) Alternative means of supplying equivalent benefits may have different costs per MWh because they involve customized choices of technologies that are timed and designed specifically to serve the specific pattern of needs of the utility.

In contrast, risk management generally involves standardized, traded products that can be used by any wholesale market participant. Their purpose is not to reduce costs but to limit the range of potential costs for a resource plan with a given expected cost. In a competitive and active, liquid market, all the available hedging instruments and contracts have (on any given day, for a given delivery period) the same expected cost and the same net present value, namely zero. This is explicitly the case for a forward contract for power, which is a commitment to transact a fixed quantity of power at some date in the future (typically a year or less forward, for power) at a stated price. That stated price has to cover, on a risk-adjusted basis, what the seller thinks the power will be worth in the spot market at the delivery time, and this is also the buyer's alternative of going unhedged (*i.e.*

[3] In practice, IRP filings usually consider several measures of cost over time and across different scenarios or market conditions, so the evaluation also takes into account extreme risks and robustness. The point here is not to characterize IRPs fully, but to draw a distinction between least cost planning and risk management.

buying in the spot market). So the contract trades at a fair price which gives neither of the parties an expected gain or loss compared to not hedging at all. For that reason, the contract has zero value on the day it is bought, and no money is exchanged between the parties. They have each made offsetting future promises to each other that are matched in value.

Q. Do all hedging instruments have an expected present value of zero?

A. Yes, this is true in general of hedging contracts at the time they are initially traded, even when they are asymmetric in their payoffs. For instance, a call option gives the buyer the right to take an asset in the future at some fixed price, and it will only be exercised if doing so is then attractive. That is, a call option gives the buyer the benefit of any upside movement that could happen to the underlying asset by the delivery date. Since there is some possibility of such price appreciation occurring for any volatile asset, an option is valuable today even if it is not yet attractive to exercise. But the buyer has to pay a premium to obtain the option, and that premium is equal to the present value of its future potential exercise value. So the net value of the option on the day it is acquired is zero, just like a forward contract.

Risk management contracts can and do change in value after they have been acquired, but this is no different than a physical resource. If the future (expected or forward) price of power goes up, a plant or contract that gives the holder the right to future MWhs of production or delivery also goes up in value, while the obligation to produce or deliver goes down in value. However, with a hedged contract, the delivered cost of that transaction can be designed to not go up or down with the market (while the operating costs of a power plant may do so), so the total cost to the contract holder (or customer of the utility) will not change over the hedging horizon, despite the change in market value (or replacement cost) of the product or service. The art of risk management is to identify the type and timing of procurement for a set of hedging instruments that will restrict the distribution of future potential outcomes to an acceptable range, and to monitor and adjust the hedging positions over time to stay within those risk bounds as much as possible when market conditions change.

NO ENDOGENOUSLY DETERMINED OPTIMAL AMOUNT OF RISK TO BEAR

Q. How much risk should a utility like Rocky Mountain Power bear?

A. A common misperception of risk management is that there is some optimal amount of risk to bear that can be discerned from just the statistical properties of how much the production inputs and outputs tend to change in value over time, and how much it costs (if anything) to buy the various kinds of hedges that are available in the market. This is not feasible. The desirable amount of risk reduction to pursue depends on the consequences of being exposed to the potential extremes in costs that might arise, not on the extreme costs themselves. That is, it depends on the risk tolerances and side-effects of extreme outcomes on the affected parties. For instance, if high prices could occur that would exceed the budget limits of the buyer (or its customers) which in turn causes <u>other</u> problems then it is worth pursuing hedges that keep the range within budget limits. But it is those third-party budget limits and adverse consequences to high prices that determine how much risk management is worthwhile, not the risk properties of the costs or assets being hedged themselves.

As a practical consequence for the proposed ECAM, this means that Rocky Mountain Power needs to base its risk management goals and practices on the benefits of protecting its customers from disruptive cost variability and of preserving its own financial health. Initially, that can occur based on the utility's implicit understanding of past regulatory and intervener concerns over price changes, but eventually the right amount of risk management should become a policy that is decided with input and guidance from the Commission and customers. In general, Rocky Mountain Power can manage its ECAM risks to constrain likely costs to almost any *ex ante* risk range that is desired, within the practical limits of how much risk can be eliminated (discussed in Section V below). Rocky Mountain Power's own tastes for risk are not necessarily sufficient to identify what amount of risk reduction is best for its customers.

Q. What other considerations are there in developing a risk management program?

A. Closely related to considering third-party impacts in order to set risk goals is the problem that "risk" is a term used casually to describe several different situations, some of which are conflicting. The formal economic notion of risk is *a priori* exposure to future price, cost or volume uncertainty. If that uncertainty is eliminated with forward contracting at a fixed price, or by having an insurance contract bear any and all costs that depart from a fixed target, then economic risk is eliminated. However, this may not be what customers, regulators, or politicians mean when they speak of wanting a "low-risk strategy" from the utility. They may want low uncertainty about future prices while also wanting a low possibility that realized costs will be much different (esp. not much higher) than the costs that would have occurred had the hedging not been in place. Technically, this desire to have a good outcome in hindsight is about "regret" avoidance rather than risk reduction, and the two are in fact competing goals. More risk reduction increases the fixity of future costs, thereby increasing the potential for regret if/when the cost of some later-emerging alternative proves cheaper. To balance these conflicting goals, an explicit tradeoff must be articulated and agreed to with input from external parties.

Q. Over what time intervals should risk be managed and monitored?

A. The time intervals over which risk should be monitored and managed are also a political and regulatory judgment. In particular, there is debate in the regulatory economics community over whether customers are best served by reducing rate variability to very low levels over long periods of time, with occasional potentially large adjustments, or are better served by gradual, frequent, smaller changes in rates. The gradual approach is less stable and predictable in the short run, but also less susceptible to dramatic changes. Either way, the same average cost of power is incurred over very long periods of time. To some extent, adopting an ECAM is implicitly a decision that gradualism is preferred. Frequent changes provide more efficient price signals to customers about how the costs of their electricity service are changing. And, gradualism allows customers to make more timely adjustments to their consumption habits and energy infrastructure, such as home appliances. It is instructive that last year's steady growth in gasoline prices (from around $2.50 to over $4/gallon at the pump) produced customer frustration but less political outcry than was experienced by some electric utilities making often much smaller rate changes after several years of rate freezes.

MEASURING RISK

Q. Once those decisions about horizon and desirable extent of risk to bear are "settled", what tools and techniques can be used to keep track of it.

A. To manage risk, it must be measured rigorously and consistently. Risk should not be confused with predictable variability. It is colder in the winter than in the summer, and the extent to which that is predictable is not a weather risk. Weather risk arises to the extent we cannot predict the temperature, *i.e.*, from the variation around what we expect. The same is true in economics. The price of natural gas varies seasonally, being generally a dollar or so per MMBtu higher in the winter than in the summer. The price of power varies within each day, as load increases from low levels in the early morning to a peak around 5-7 p.m. at night in many parts of the U.S. These predictable cycles are not price risk, and there is nothing risk management practices can do to eliminate them. The cost of such expected variation in fuel and power will be reflected in any contract that a utility pursues. It may be smoothed out across time, *e.g.*, in a fixed price contract, but that merely means that the seller is financing the difference between these cyclical costs and the fixed price, and charging the buyer for the carrying (interest) costs.

Q. How should risk be measured by electric utilities such as Rocky Mountain Power?

A. One of the most widely used measures of risk is called “VaR”, an acronym for “value at risk”. For a utility, this is a measure of how much the unhedged portions of its power supply portfolio could change in cost over a given time frame with some stated probability. (For an electric utility, the core elements of its “portfolio” consist of the output and fuel contracts for all of its generation -- where the output contract may really be just a tariffed rate – along with financial hedges they have and any future uncovered obligations to buy or sell power or fuel. In some cases, environmental allowances, transportation and transmission services, ancillary services, and the like may also be included.) Typically, companies keep track of the potential distribution of daily changes in their portfolio’s value over the next few months or years.

Q. How is VaR calculated?

A. To calculate the VaR, the possible daily change in portfolio value is simulated, based on either historical or market-implied measures of likely volatility for the key inputs (like purchased power and natural gas prices), and a distribution of possible next-day values (for the portfolio over the position management horizon) is created. The VaR calculation then often focuses on what change in value has only a small chance of being exceeded -- typically a five percent chance of being exceeded is used. This is equivalent to determining the range of values that span a 95 percent confidence interval for tomorrow’s possible change in the value of the portfolio. Based on this range, a utility can pursue hedges that keep the 95th

percentile of potential changes in value to within some tolerable value, called the VaR limit. If the utility's hedging is successful (and its estimates of volatility are accurate), then the observed actual changes in the value of its portfolio should be smaller than this VaR limit in about 19 out of every 20 days.

Q. Does VaR change over time?

A. Yes. The VaR of a portfolio changes over time (daily), as market forward prices and the composition of the portfolio changes. If the VaR exceeds the VaR limit, the risk management strategy can be accelerated or modified (to add more hedging). Thus, VaR is a sort of barometer for how much variability can arise in the portfolio from day to day and for how well the risk management practices are doing at keeping the daily variability to a financially manageable level. It can also be calculated over other time frames and at other probability levels. In general, a longer time frame or a higher level of confidence both increase the VaR, but not necessarily in some smooth way. It may be that the extreme risks of what could happen in the 5 percent worst possible outcomes have a different pattern than the risks inside the 95 percent confidence interval.

Q. Are daily calculations of VaR sufficient to ensure a portfolio remains under desired risk tolerances?

A. While VaR is a useful risk management tool, it will not generally be enough by itself to keep the portfolio on track. Day by day, a portfolio could be kept within its VaR limits but still be becoming steadily more expensive. There may be little that can be done about such steady trends, because as described above, hedging cannot be used to "beat the market." But it is important to keep track of any such persistent drift and to reevaluate the portfolio strategy if the cumulative losses (or gains) become large enough. Typically, a portfolio will be managed to have different thresholds for a worrisome short term (*e.g.* monthly) movement vs. a longer term (seasonal or annual) cumulative movement. The thresholds of review are called "stop-loss" limits. On Wall Street, a portfolio manager can often put a halt to cumulative drifting of a portfolio's value by simply selling off the troublesome securities. Unfortunately, an electric utility often has far less discretion or opportunity. The problem may be arising from an asset the utility must have (such as a gas plant) in order to serve load, or it may be occurring at a location on the grid for which there is no substitute resource available and no counterparty willing to sell a hedge. In such cases, the utility may only be able to report to the Commission that a trend has emerged which is causing higher prices – but at least the risk management system catches the trend as it unfolds and provides the opportunity for a timely discussion with the Commission and with customers.

Q. Does the Company have in place a platform for estimating VaR and keeping VaR under established tolerance levels?

A. Yes, as described in more detail in Section VI, the Company has risk management analytic tools in place to calculate the VaR of its electricity and natural gas positions and to monitor the stop-loss limits on changes in these portfolios. It also has significant experience with a particular strategy for hedging those costs, via hedging targets over time for largely covering all of the near year of expected needs for both gas and power and for also hedging a good portion of the needs projected typically as far as four years forward. Importantly, those targets focus on hedging of the obligations of the electricity distribution companies to serve their customers. The Company does not pursue trading activities for its own profits, but does seek short run arbitrage opportunities to benefit its customers when similar products are available at inconsistent prices.[4] These targets and risk metrics can be monitored and reported over time to help the Commission understand the performance of the ECAM costs, and they can be revised occasionally to achieve modified goals for ECAM risk.

RISK MANAGEMENT PERFORMANCE EVALUATION

Q. What features should utility risk management programs have to achieve desired risk reduction outcomes?

A. In general, it is a good idea for a utility to be implementing the majority of its hedging transactions under fairly mechanical schedules and rules for when to buy what types of contractual positions. The risk performance of a set of strict purchasing rules can be tested (via simulation) before the rules are put in place, to see if they accomplish a reasonable result (tolerable range and shape of possible future costs). An *ad hoc* strategy that simply hedges opportunistically, *e.g.*, whenever hedges appear to be favorably priced relative to historical averages, cannot be tested *a priori*. Ad hoc hedging also invites hindsight criticism that some other type or timing of purchase decisions was not pursued. On the other hand, it is sensible to take advantage of market intelligence that a utility such as Rocky Mountain Power may have about how disruptive or dramatically shifting

[4] The hedging targets, VaR and stop-loss limits apply to the company's fixed price exposure and do not address physical delivery risk. Physical delivery risk is addressed independently and does not address net power costs.

conditions may affect it uniquely. Thus, some discretion in the precise timing of hedging purchases is reasonable, and Rocky Mountain Power's careful monitoring of its VaR and its stop-loss limits will prevent any speculative efforts to substantially "time" the market.

In sum, risk management is not something that can or should be done to "beat the market" or to "lower expected costs." It is done solely to limit the range of potential price movements around the expected value, where the latter is determined by the combination of long run assets in place (physical plant) and the prevailing forward market prices of fuels and spot power. But as shown above, those fuel and power markets can be very volatile, so controlling their range is not a trivial task, nor an inconsequential benefit.

Q. What are the ramifications of the goals and capabilities of risk management for how it should be evaluated?

A. Risk management practices should be evaluated in terms of how well they manage risk, not what the *ex post*, realized costs of the hedging program are in comparison to some other hypothetical procurement or hedging strategy. The relevant performance question is whether the risk management program adhered to its rules, targets and schedules with the allowed hedging instruments, and monitored its risk containment goals in a timely fashion. If so, it was a prudent and effective program, regardless of whether the outcomes were above or below the costs of some alternative strategy. In hindsight, there will <u>always</u> be one or more ad hoc strategies that would have involved more opportune timing and types of hedging investments and a lower resulting total cost – but that does not make them better risk management nor a relevant benchmark.

V. LIMITS ON THE ABILITY OF ROCKY MOUNTAIN POWER (OR ANY OTHER UTILITY) TO FULLY CONTROL ECAM RISKS EVEN WITH AGGRESSIVE HEDGING

Q. Can utility hedging programs remove all the cost and quantity risk associated with fuel and power purchases?

A. No. Even a very sophisticated and elaborate hedging program cannot control the price of future energy to within extremely narrow tolerances, and it cannot withstand the forces of long-term, fundamental change in the industry, for several reasons. First and foremost, the available hedges are not "complete," meaning they do not span all the possible risk factors and contingencies that could alter future needs or the opportunity cost of covering those needs. In particular, hedges are not generally available for distant time periods in the future, so the best that can be done to manage the changes in costs that arise over a long period is to gradually fold near- to mid-term hedges into the portfolio. This will not eliminate the eventual changes in cost, but it will spread their recognition over longer periods of time. Second, it is impractical to attempt to eliminate all risks, even if it was possible in principle to do so. Hedging is a time, money, and human resource-consuming activity that must be balanced against other uses of those assets and capabilities. As a result of practical tradeoffs, some items will remain unhedged and others will be simplified or ignored in forecasting and risk simulation models. This creates inevitable, but reasonably expected, estimation errors and gaps in hedging coverage. Third, the hedging process involves implicit assumptions that the current best estimates of riskiness and the relationships among key factors (*e.g.*, based on past volatility or current market-implied volatilities and correlations) will in fact describe the future, so that one kind of risk can be predictably used to offset another. However, the world is not always so well-behaved and cooperative. Market parameters change in unforeseen and unforeseeable ways, invalidating prior hedged positions. More specific examples of how these limitations on feasible hedging arise are discussed below.

UNHEDGEABLE ATTRIBUTES (INTRADAY LOAD SHAPE, OUTAGES)

Q. How well do available hedging instruments correspond to the service problem the utility is trying to solve?

A. Most of the hedging contracts that are widely available in the wholesale market are for fairly simple and standardized energy requirements, over a fairly short forward horizon (often only a year or two). The actual loads the utility must cover have much more complicated and uncertain dynamics and of course, the need extends indefinitely into the future.

For instance, the standard contract for forward power is a 25 MW (fixed quantity) for all of the "on peak" hours from 7:00 a.m. to 11:00 p.m. Mountain Prevailing Time on Monday through Saturday, excluding holidays, for an entire month. The available location for delivery is also restricted to market centers where large volumes transact, but unfortunately, remote locations where few buyers other than the local utility transact business are quite common in the power industry. Standardization makes these contracts highly fungible, so that a buyer or seller can get out of them, and/or cover them readily with other similar standard contracts with other buyers or sellers. However, this standardization means that it is difficult to cover the complex (uneven, irregular, weather dependent) load shapes of retail load customers over long periods. (The duration of available hedges is fairly short, because the risk that the initially offered price will diverge greatly from the realized price increases with time, and this risk also increases the potential inability of the counterparty to honor the deal.) About the best that can be done is to cover the average requirement with a collection of contracts of different horizons, layered somewhat like a wedding cake to approximately cover the true load shape, and rolling those hedging positions over to replacement contracts (at new prices) as they expire.

Thus even if a utility were able to hedge 100 percent of its expected fuel and power requirements over the next year or so, it generally will have only dampened but not removed all of the cost risk associated with serving its customers in that period or beyond. For instance, some risk always remains due to unanticipated variations in load shape due to weather. A utility can either bear this risk by itself and cover the volumetric uncertainty with spot purchases passed on to customers, or it can transfer the risk to a supplier who will charge a risk premium for bearing this volumetric and load-shaping risk over time. The latter would result in the higher average costs for customers. Unexpected generating unit outages and unplanned maintenance are a few other sources of uncertainty practically every utility faces, for which there are no standardized hedging contracts or traded products.

FUNDAMENTAL MARKET SHIFTS AND UNSTABLE RISK PARAMETERS

Q. How do fundamental market shifts limit a utility's ability to hedge all of its cost risks?

A. Energy markets have exhibited tremendous price variability over the last few years, and some of this is related not just to short term aberrations in supply and demand conditions but to shifting beliefs about the long term value or cost of energy resources. Since just last summer, the spot and forward prices of gas and power have both declined markedly, apparently in reaction to the recessionary pressures created and revealed by the credit crisis. Parameters that described pre-crisis energy markets may no longer capture the current or long run energy markets in a recessionary environment, so they will need to be closely monitored and perhaps updated periodically.

There are also emerging issues that could fundamentally alter the economic landscape of energy pricing. The most obvious of these is the movement towards climate protection policies via carbon pricing (*e.g.*, under a cap and trade regime as proposed in the Waxman-Markey bill). Besides adding an uncertain and potentially quite large surcharge to the cost of fuels, these policies may change (in fact are designed to change) the viability of conventional generation technologies, alter transmission flow patterns and basis differentials for buying and selling power across distinct locations, and induce significant load conservation. Under such circumstances, the parameters describing typical risk profiles and relations between different energy types will change in ways that hedging models and markets can not fully anticipate.

The climate policies now being considered are an example of the uncontrollable regulatory and political risks that utilities face that complicate a utility's planning and operational control processes and ultimately cause some *ex post* market conditions to be significantly different than *ex ante* assumptions that may have been highly credible when earlier decisions were made about power and gas procurements. For instance, renewable resources like wind may prove to be uneconomic unless tight limits on carbon emission are set by Congress and a strict cap and trade or carbon taxation program is approved. Or, natural gas-fired power plants may be dispatched more heavily if coal-fired plants are displaced as a result of cap and trade programs, making prior gas procurement targets too low in retrospect. Such shifts are inevitable but not predictable.

OFFSETTING COSTS/RISKS – CREDIT, COLLATERAL COSTS INCREASE WITH MORE FORWARD HEDGING

Q. Can hedging programs result in offsetting costs and risks?

A. Yes. The above discussion of how to define "risk" mentioned that there is often a desire to manage both true risk and *ex post* regret over whether hedged positions turned out to be as attractive as alternative procurement arrangements. Even if one is not concerned about regret, and is willing or inclined to hedge extensively forward, there can be competing costs and risks that accompany this approach. In particular, a longer and larger forward position entails both credit and collateral risks that can become prohibitive. When a company chooses to lock down future prices (especially far in advance of delivery), it becomes more vulnerable to intervening price changes and resulting financial performance concerns about (and from) the counterparty to the contract. These concerns arise from the possibility of supplier failure and/or the consequences of mark to market accounting and cash collateralization obligations for positions that become "out of market."

For example, a fixed-price purchase made by a utility that becomes highly valuable in a rising price environment exposes the utility to the credit risk of its counterparty. If the counterparty fails to deliver at the committed price, the utility is exposed to having to replace the purchases at a higher price. Conversely, if the market price for replacing that contract should drop significantly, the seller may become skeptical of the utility's ability or willingness to consummate the purchase, so it may insist that the utility post cash in an escrow account sufficient to cover the difference between the quoted price in the contract and the prevailing market forward price. For a large, long term contract, this can potentially be very large amounts of cash. Even if this collateralization is avoided, the imputed cost of debt from long term forward commitments to purchase power or fuel at fixed prices for a utility may also raise the cost of long-term forward hedging. Thus, there is "no free lunch" in hedging or anywhere else. At some point, it is better to leave some of the future unhedged rather than have to face all of the attendant financial performance burdens and risks.

LACK OF LIQUIDITY IN HEDGES BEYOND NEAR TERM

Q. Are there limitations to hedging out-year risks?

A. Yes. Most of the standard hedging wholesale contracts are actively traded in the near-term (up to one to two years out), but are much less frequently traded in the more distant, years forward. The market for hedging contracts becomes less traded in the long-term, so liquidity becomes an important factor in determining how much to hedge in the long-term. Illiquidity impairs hedging in several ways. It can mean there is no hedging contract available, or at least no standard one that can be evaluated simply in terms of how its price compares to other similar products. Or it can mean there is no buyer available to get out of a contract, if/when it becomes unattractive to continue holding. The only way to liquidate a position may be to reduce its price well below what seems to be its intrinsic value, in order to find a buyer. Illiquidity may also be felt as high bid-ask spreads (again raising the costs of moving in and out of positions) or substantial transaction costs and risk premiums. All of these barriers and frictions tend to make hedging more difficult and less likely to succeed. As a result of these limitations, utilities may need to wait to hedge upcoming expected requirements, which can result in hedges not being undertaken until after possible market shifts have occurred that cause unforeseen increases in gas and power expenses.

FORECASTING AND ESTIMATION ERRORS IN KEY FACTORS

Q. How does a utility's forecasting limit a utility's ability to hedge its cost risks?

A. 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. For instance, if the actual load turns out to be higher than forecasted, a utility will need to cover the shortage through spot market purchases (either of power or of natural gas if its gas-fired power plants are available to generate at above-forecasted levels). Typically, these supplemental purchases will occur at higher prices than was originally forecast or locked in for the rest of the portfolio, because the new need is incremental and unexpected. And if the actual load is lower than forecasted, the utility will need to sell some excess energy to the market, possibly at a loss relative to the acquisition price. The timing of the load forecast error is also important. Since buying during peak periods is more expensive than buying during off-peak periods, errors in the load forecast during peak periods are more costly than during off-peak periods. So a utility may hedge peak periods more heavily and leave off-peak periods more open.

Correlations among factor inputs are another very difficult to forecast element that affects the success of hedging. As was seen in Figure 4, gas and electricity prices tend to move somewhat in tandem, but quite imperfectly. Sometimes, the price of gas is driven by competition with coal plants, while at other times it may be driven by competition with oil or other sources of natural gas. Thus, the extent to which gas can be used to hedge electricity varies over time and circumstances.

Q. Is this a pervasive problem or is it restricted to the gas-electric relationship?

A. It is a pervasive issue – not sufficient to make hedging unproductive, but sufficient to make it imprecise and somewhat of an art. For instance, the concurrent prices of electricity at various locations on the PacifiCorp network will tend to be correlated, but some regions may go up in cost while other regions do not; *e.g.*, if there is local congestion in one part of the network that is not felt elsewhere. This means not all of the electric supply contracts in a portfolio will act the same way, again making them more complex to simulate and to hedge. There is a significant amount of this uncertainty that is simply unresolvable. No amount of more sophisticated analysis is going to settle what the "true" underlying relationship is or will be, because it depends in large part on random events such as plant or line outages, OPEC activities, and the like.

MODEL INCOMPLETENESS

Q. Earlier, you said there are practical limits to modeling that result in some factors being simplified or ignored. Please elaborate on how this might arise for Rocky Mountain Power.

A. No forecasting model or risk simulation system is perfect. After all, they are <u>models</u>, not the real world, which inherently means they use simplified mathematical representations of what is really going on. All models rest on a simplifying set of assumptions which are rarely met in real life. For instance, predicted load cannot be forecasted with pinpoint accuracy because a number of factors, like weather swings, cannot be perfectly anticipated, even statistically. Or, whenever pending regulatory policy changes have yet to be specified, they can only be represented loosely. In the current situation, Rocky Mountain Power only considers the stochastic effect of CO_2 prices via scenarios in its long run IRP planning, since actual CO_2 prices are only likely to affect the last few months of the 48 months it simulates in its hedging modeling platform. Similarly, Rocky

Mountain Power does not yet simulate the variability in daily wind speeds and resulting wind generation, though it may eventually need to do so as the wind share of its supply mix increases. What factors to include or omit is a judgment call based on the quality of available data, the complexity of adding the capability to the model, and the leverage that factor tends to have on the results. Over time, the needed elements in the model will evolve.

VI. THE COMPANY'S HEDGE PROGRAM IS WELL-SUITED TO CONTROLLING ROCKY MOUNTAIN POWER ECAM COST RISKS

Q. Have you reviewed the Company's risk policy and procedures?

A. Yes. I have reviewed the Company's risk policy and various monitoring reports that have been provided to me by PacifiCorp. I have also spoken to employees responsible for managing, measuring and monitoring the Company's risks.

Q. What conclusions do you reach regarding the Company's existing policies and risk management capabilities as they relate to the proposed ECAM?

A. The Company's existing risk policy and hedging capabilities are sophisticated, well-developed, and suitable for monitoring and managing ECAM risks over time. No risk platform can eliminate risk, but it is possible to substantially reduce the short- to mid-term variability in net power costs that will flow through the proposed ECAM. The Company has in place an advanced platform for estimating and reporting the mark-to-market value of, and risk metrics pertaining to, its electric and gas portfolios. These metrics are reported and reviewed on a daily basis and the Company is required to quickly resolve movements in its portfolio beyond established risk limits that have proven effective in the past in controlling costs.

Q. What are the main components of the Company's risk program?

A. The main components of the Company's risk activities that serve to reduce customer exposure to fuel and power price volatility are VaR measurements and VaR limits, hedging targets and schedules, position limits, and stop-loss limits that are outlined in the Company's risk policy and procedures. These limits and targets force the Company to closely monitor the open positions it holds in power and gas on behalf of its customers (which it does on a daily basis) and to limit the size of these open positions by prescribed time frames in order to dampen customer exposure to price volatility. Thus, for example, the company cannot simply choose to procure all of its expected natural gas requirements on a spot basis, nor can it choose arbitrarily when or how long forward to hedge. The Company has a substantial natural short position in natural gas because of its ownership of gas-fired electric generation (requiring it to purchase large quantities of natural gas to generate power for its customers). The risk policy requires the Company to purchase gas well in advance of when it is required to reduce the size of this short position. Likewise, on the power side, the Company either purchases or sells power in advance of anticipated open short or long positions to manage price volatility on behalf of customers.

Q. How does the Company use VaR?

A. The Company calculates the VaR of combined electricity and natural gas portfolios on a daily basis using historical percentage changes in forward prices applied to current forward prices. As discussed above, the Company's VaR calculation estimates the potential loss (not expected to be exceeded at the 95th percent confidence level) over one trading day for the current 48-month portfolio (as it evolves over time). The current VaR limit for the forward 48-months from the current mark-to-market date is a reasonable and fairly tight threshold, based on historical observations of what has been feasible and what range of variation in potential exposure is typical from day to day. VaR estimates will vary as the composition of the portfolio changes and the state of the market changes even though the VaR limit does not change.

Q. Has the Company stayed within its VaR limit?

A. Yes. The Company's daily VaR has remained well below the VaR limit (see Figure 7 for the calculated daily VaRs as a percentage of the VaR limit). In addition, the Company has monitored the actual daily changes in the value of its portfolio and has observed that the actual changes in value have been below its estimated daily VaR over 95 percent of the time. This is an indication that the parameters being used to estimate risk are reasonably accurate (if not a bit conservative) and that past hedging has been fairly successful.

[redacted]

Q. How is the Company able to stay within its VaR limits so reliably?

A. Rocky Mountain Power is able to stay within these tight VaR tolerances primarily because it is so thoroughly hedged pursuant to its existing hedge program. This hedge program contains hedge volume targets for net power purchases and natural gas over a prospective 48-month period with relative higher hedge volume targets in the first two years compared to the last two years**.** [redacted] The Company estimates its net requirements (*i.e.*, its expected long and short positions in power and gas) by modeling the expected dispatch of its portfolio of generating assets. The Company's requirements therefore depend on prevailing forward gas and electricity prices, expected load, and expected unit availability/dispatch.

[redacted]

The hedge volume targets are lower in years two through four because (i) there is more uncertainty about those requirements, (ii) they cover some of their needs with a “dollar-cost averaging” approach in which installment purchases are made at different points in time, and (iii) because markets for standard hedges are thinner in more distant years.

The Company’s hedge program is not overly prescriptive such that it must make all of its installment purchases at specified intervals to meet its hedge volume targets. It monitors electricity and gas market fundamentals and may deviate from plans somewhat in light of unexpected market conditions that it may view as temporary or short-lived. For example, hurricanes may impact forward prices for some periods of time and the Company may choose to alter its procurement practices following a hurricane if it believes the forward price impact may be short-lived. While the Company has made exceptions to its hedge targets in light of unfavorable market conditions, it rarely makes exceptions to its VaR limits, which reduces customer exposure to price and volume volatility even if exceptions are made to hedge targets.

Q. Please explain the stop-loss limits the Company uses and how they can affect the portfolio.

A. The Company tracks daily the changes in the mark-to-market value of its portfolio and has stop-loss limits in place that are designed to limit cumulative losses in the value of its portfolio that may occur over a monthly or annual basis as a result of fundamental price movements that result in losses that are realized over extended periods. If the specified monthly or annual thresholds are reached, management meets to discuss the actions to be taken in response (*e.g.*, potentially entering into additional hedge transactions). These limits, coupled with VaR monitoring, help to discipline the freedom to simply buy opportunistically. That is, this helps to avoid the danger of deferring hedges when prices are rising (because it seems that prices are unfavorable relative to past levels) when risks may also be rising (hence deferring purchases could result in wider VaR exposure).

Q. Are the Company's risk management activities an alternative to Rocky Mountain Power's proposed ECAM?

A. No. Even though the Company's risk management activities are sophisticated and well-developed, they should not be viewed as an alternative to the Company's proposed ECAM. As I discussed in Section V, even with an elaborate hedging program, Rocky Mountain Power will not be able to remove all risks or control the cost and quantity risk associated with its fuel and power purchases/sales within narrow tolerances. The ECAM is needed to ensure timely and reliable recovery of these costs and to avoid adverse impacts on Rocky Mountain Power's financial health. Thus, while the Company's hedging activities are useful for limiting customer exposure to ECAM risks, these activities do not eliminate the need for the proposed ECAM.

VII. CONCLUSIONS

Q. Please summarize your key conclusions?

A. I find that the ECAM proposed by Rocky Mountain Power is reasonable in light of the inherently volatile and largely uncontrollable nature of its Net Power Costs. More specifically, I reach the following conclusions:

- Rocky Mountain Power and its customers face unavoidable and largely uncontrollable operating costs and quantity risks as a result of circumstances that are intrinsic to the industry. These include the highly volatile costs of fuel underlying a significant portion of the Company's portfolio of generating assets, its substantial reliance on renewable and time-dependent (uncontrollable) generation resources, and the inherent uncertainty in load, and the practical limitations on any utility's ability to precisely forecast or fully hedge some of its key uncertainties.
- Recently, the industry risks appear to have increased, and it is plausible they will continue to do so over the next few years. At the same time, the need for utilities to be financially strong, and for customers to receive efficient price signals about the value of the power they consume, have also increased. The proposed ECAM can advance both of these goals, while simplifying regulation.

- Hedging, though not necessary for using a fuel and purchased power adjustment clause, can help dampen unexpected swings in NPC that will be collected under the ECAM. However, hedging cannot be expected to reduce the average cost of power relative to other procurement strategies, and it cannot be expected to eliminate all ECAM risks. Therefore, an effective hedging program is not a viable alternative to the proposed ECAM.
- Rocky Mountain Power has sophisticated risk management capabilities and practices already in effect within the Company that reduce the variability of ECAM costs. These risk reductions are the result of very substantial hedging quantity targets, a tight VaR limit, and other risk-control protocols that have been adopted and applied for several years. These practices cause the Company to limit and closely monitor the open positions it maintains in fuel and power, which reduces customer exposure to power and fuel price volatility.

Q. Does this conclude your testimony?

A. Yes it does.