I. WITNESS INTRODUCTION, PURPOSE OF TESTIMONY, AND SUMMARY OF CONCLUSIONS

Q. Are you the same Karl A. McDermott that provided supplemental direct testimony in this docket?

A. Yes.

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

A. I respond to portions of the direct testimony of Mr. Charles E. Peterson on behalf of the Division of Public Utilities ("DPU Phase I Exhibit 1.0"), Ms. Michele Beck and Mr. Paul Chernick on behalf of the Utah Office of Consumer Services ("Beck Dir." and "Chernick Dir."), Mr. Steve W. Chriss on behalf of Wal-Mart Stores Inc. and Sam's West Inc. ("Chriss Dir."), Mr. Kevin C. Higgins on behalf of Utah Association of Energy Users ("Higgins Dir."), Ms. Nancy L. Kelly on behalf of Western Resource Advocates ("Kelly Dir."), and Ms. Elizabeth A. Wolf on behalf of Salt Lake Community Action Program ("SLCAP Exhibit 1.0").

Q. What are your overarching comments concerning the testimony filed by the various intervenors in this docket?

A. First, it is worth remembering what this phase of the investigation concerns. I understand that the Commission expects the record to answer the question of whether the "adoption of *an* ECAM is in the public interest."[1] To address this question, the Commission requested that several issues be examined.[2] These issues largely relate to the question of whether a cost tracking mechanism can be a

[1] "Notice of Scheduling Conference and Procedural Order," UPSC, June 18, 2009 in Docket No. 09-035-15, p. 9 (referred to as the "Procedural Order") (emphasis added).

[2] Id., pp. 9-10.

viable and useful tool in regulating public utilities. While the examination of the issues listed in the Procedural Order is useful to put the evaluation in context, I agree with DPU witness Mr. Peterson's insightful observation that "some cost recovery mechanism reasonably could be put in place… [T]he issue becomes one of design and not so much one of whether, in the abstract, a power cost adjustment mechanism is in the interest of both Rocky Mountain Power and ratepayers." (DPU Exhibit 1.0, 7:149-152) Indeed, alleged design flaws in the proposed ECAM seem to permeate the concerns of some other intervenors. For example, Wal-Mart Stores Inc. and Sam's West, Inc. witness Mr. Chriss states in his conclusion that the ECAM, *as proposed*, is not in the public interest and goes on to express his concern over the lack of an ROE adjustment and the lack of "transparency in rates" that he claims is a "major benefit of transitioning to a fuel clause." (Chriss Dir., 3:7-16) In my view these issues are a matter for design, not policy. The matter of an ROE adjustment should be taken up at the time of the next general rate case. Further, Mr. Chriss's concern over price transparency is a legitimate regulatory objective and such design issues can be addressed. Indeed, DPU witness Mr. Peterson identifies pricing as a potential concern, although for the design phase of this investigation. (DPU Exhibit 1.0, 24:564-571)

Second, there is a fundamental disconnect between theory and reality in evaluating the three-prong test for public interest of the ECAM. The three-prong test for adjustment mechanisms asks whether the costs under review are large, volatile, and largely out of the control of the utility. Although all of the intervenors acknowledge the appropriateness of this three-pronged test, some suggest ratemaking approaches that are simply unavailable or request proof beyond a reasonable doubt. For example, Mr. Higgins claims that volatility can be adequately addressed through other means. (Higgins, Dir., 12:237- 15:310) However, this clearly is not the case, (see Rebuttal from Company witness Graves). If it were that simple, PacifiCorp would have no need for the ECAM. Would it not be easier for a utility to buy a contract for natural gas or electricity, if it could, and include that cost in the base rate calculation rather than going through an ECAM proceeding? It is not credible to argue that the utility has all the tools it needs today to address these issues. (Id.) Further, it seems that the question of volatility is relative. There is no magic metric one can review to see if a particular expense is volatile, but as shown earlier, PacifiCorp's Net Power Costs (NPC) are more volatile than other costs typically included in rates. (McDermott Sup. Dir.)[3] Therefore, Mr. Higgins's absolute measures of volatility miss the point entirely. (Higgins, Dir. 14:282-305) Moreover, as explained later in this testimony, Mr. Chernick uses a simple arithmetic trick of rearranging data to show that volatility in a set of numbers can be manipulated. (Chernick Dir., 21:491-497) This, while true, misses the point, because the data I used was the actual data over time, not a manipulation of arbitrary data. Furthermore, the standard deviation and coefficient of variation, derived from the variance of a set of data, provide standard methods of evaluating volatility.[4] It is interesting to note that Mr. Chernick does not refute the proposition that NPC are volatile or are

[3] *Also see* McDermott Supplemental Direct Testimony for a discussion of why the relative volatility of NPC is important in traditional ratemaking.

[4] *See e.g.,* R. A. Brealey and S.C. Myers, *Principles of Corporate Finance*, McGraw-Hill, 2003, pp. 163-165 or J.C. Hull, *Introduction to Futures and Options*, Prentice Hall, 1998, especially Chapter 7.

more volatile than other O&M costs; he simply claims that PacifiCorp has not met *his* high standard of proof.[5]

Third, there is much concern expressed about possible poor incentives as a result of approving an ECAM. (*See e.g.*, Chernick Dir., Higgins Dir., SLCAP Exhibit 1.0, and Kelly Dir.) I maintain that, beyond the general question of whether an ECAM in any form harms incentives to operate efficiently, this concern is a matter for the design phase as well. I find it extremely difficult to believe that the vast majority of regulators in the United States have been fooled into purposely implementing a regulatory policy that would create less efficient utilities, on net, and would maintain those polices, in many cases, for decades.[6] The evidence provided in this docket shows that design questions are important and different regulators choose different designs based on their individual preferences and local issues. The premise that regulators choose to utilize ECAMs to create unjust and unreasonable rates is untenable.

Fourth, there seems to be confusion between risk and cost recovery. Many intervenors claim a shifting of risk as a result of an ECAM. This claim apparently results from a conclusion that prudently incurred costs that currently are borne by shareholders, because of the persistent under-forecasting of NPC, (and thus are not being recovered in rates under the current methods allowed by the

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[5] Mr. Chernick clearly has a different view of the standard for proof then either Mr. Peterson in this case or the staff of the Idaho Commission when reviewing this issue for PacifiCorp's Idaho property (as cited in McDermott Sup. Dir., 28:562-567).

[6] We can argue as to whether this or that jurisdiction has the "right" ECAM, but that proves the point. We can also split hairs by pointing out that a few jurisdictions do not have significant (or any) investor-owned utilities, but again this proves the point. By relying on the outliers in the sample, we are missing the key point—nearly all regulators in the United States have implemented some form of a power cost and/or fuel cost tracking mechanism.

Commission), would be paid by ratepayers under an ECAM-type approach. Yet, this is the nature of traditional regulation. Ratepayers pay for prudently incurred costs and utilities have the obligation to provide service. Are ratepayers “at risk” when a new transformer is added to ratebase? Are ratepayers “at risk” when the cost of steel, copper, labor or any other O&M cost increases? Yes, in this sense they are, but this is the nature of the regulatory bargain. We may want the owners of utilities to pay for these costs, but it is not a legitimate argument to want to maintain a system that is biased against recovery of certain prudently incurred costs because one party benefits from this adjustment at the expense of another.

Finally, on a related theme, many intervenors claim that the regulatory process will become too rushed and complicated, such that it cannot be assured that the utility is adequately regulated. Implicit in this argument are two untenable assumptions. The first assumption maintains that Utah cannot handle such a review. Such a claim flies in the face of the fact that nearly every major (vertically integrated) electric utility in the United States has some form of an ECAM and each state commission must undertake the type of review contemplated by an ECAM. There is no credible evidence that Utah is somehow less able to undertake these reviews relative to other states or that other state’s reviews are inadequate. Further, there is a supposition that the current forecast approach to NPC debated in a regulatory hearing produces a more manageable and fair outcome. Perhaps some parties may think it easier to argue over growth rates, commodity price forecasts, and other such unknowable inputs into the rate making process. Mr. Chernick even claims that the solution to the problem might be to “improve…

[PacifiCorp's.]…forecast" by incorporating inherently complex and uncertain factors into the forecast rather than use the more obvious method of reviewing actual costs through an ECAM. (Chernick Dir., 20:481-21:488) From a former regulator's perspective, this "game playing" over forecasts reduces the legitimacy of the process and ultimately hurts utilities and customers.

II. THE PUBLIC INTEREST STANDARD

Q. What is the public interest standard?

A. The public interest standard rests primarily on the proper interpretation and application of the regulatory bargain.[7] This bargain is two-sided: ratepayers pay the prudent costs of providing service and utilities are provided a reasonable opportunity to recover those prudent costs. This is the fundamental building block of the just and reasonable rate that should be the goal of regulation.

We need to keep in mind the question that needs to be answered in deciding whether an ECAM is appropriate: does it make sense to have a separate ratemaking mechanism for NPC instead of addressing these costs in base rate cases? The conventional answer to this question, accepted by all parties in this proceeding, is that an ECAM is justified if fuel and purchased power costs are large, volatile, and largely beyond the control of the utility.

By treating large, volatile, and unpredictable costs outside of base rate cases, the timing between base rate cases can potentially increase—or, at a minimum, the issues in those cases can be narrowed. Additional time between rate cases gives a utility the incentive to control the costs under its control. However, cost pressures

[7] My discussion here is at a high level. I understand that Utah law has specific goals and objectives for rates and ratemaking that, in my view, fall from the application of this regulatory bargain. *See e.g.*, Utah Code Ann. § 54-3-1.

related to NPC—where the utility is a ‘‘price taker,’’ that procures fuel from a market or sells power into the wholesale market with no ability to control the price—can be recovered in an ECAM without harming the utility’s incentives.

Q. How has the public interest standard been applied in cases of an application of a cost tracker such as the proposed ECAM?

A. The traditional approach to cost trackers is to review whether the costs are large, volatile, and largely out of the control of the utility. Intervenors did not question that NPC are large. The issue of whether Rocky Mountain Power’s net power costs are volatile and beyond the control of the utility received considerable attention by the intervenors and will be discussed below.

A. VOLATILITY

Q. Please discuss the volatility of net power costs.

A. I refute the argument made by witnesses that the Rocky Mountain Power’s NPC may not be “volatile enough” to justify an ECAM, especially considering that Rocky Mountain Power’s engages in hedging of fuel volatility. (Beck Dir., Chernick Dir., Higgins Dir., Kelly Dir., and DPU Phase I Exhibit 1.0)

I emphasize that: (1) the intervenors ignore the fact that Rocky Mountain Power’s NPC are much more volatile than its non-power costs; (2) coal, gas, and wholesale spot electricity costs are volatile; (3) the accuracy or inaccuracy of previous forecasts does not change the volatility underlying the commodities in question; and (4) PacifiCorp’s hedging policy limits the possible range of prices paid for the commodity, although hedging is not able to fully reduce all volatility in commodity prices.

Ultimately, there is substantial evidence that natural gas, wholesale power, coal, and other parts of NPC are volatile. In my view, Rocky Mountain Power has amply met its burden of proof on this issue.

Q. Please describe the volatility of NPC in relation to base rate costs.

A. Net power costs are significantly more volatile than other components of revenue requirement such as labor, maintenance, depreciation etc., yet the intervenors ignore the fact that Rocky Mountain Power's NPC are more volatile than its non-power costs. For the 2002-2008 period,[8] NPC for Rocky Mountain Power were roughly four times as volatile as non-power costs. Mr. Chernick presents a hypothetical about smooth and volatile cost patterns but fails to rebut the argument that Rocky Mountain Power's NPC are more volatile than its non-fuel costs. (Chernick Dir., 21:498-499) Mr. Chernick does raise some technical questions with respect to the coefficient of variation. It is important to remember that the coefficient of variation is a *relative* measure of dispersion—it is meaningful in terms of a "the amount of variability present in comparison to a reference point or benchmark."[9] Thus, while a comparison of NPC *relative to* non-NPC is meaningful and useful, Mr. Chernick's hypothetical, which merely manipulates the order of one set of costs, is not. In his hypothesis, which merely

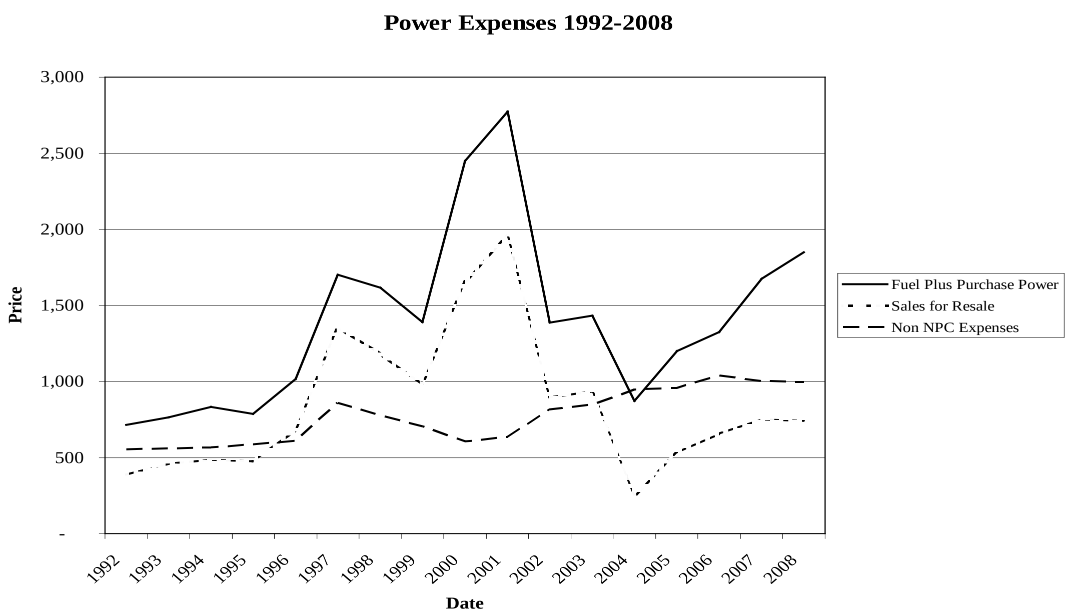
[8] I choose to look at 2002-2008 because of the power price shocks that occurred in 2000-01.

[9] DeFusco et. al, *Quantitative Methods for Investment Analysis* (Charlottesville, VA: AIMR, 2001), p. 135.

rearranges the order of a set of observations, Mr. Chernick does not compare NPC to a reference point or benchmark.

Figure 1 below graphically illustrates the *volatility* of fuel and purchase power relative to non-power costs for the full 1992-2008 period.

Figure 1: Power Expenses Relative to Non-power Costs



Mr. Chernick goes on to argue that "some of the volatility may simply reflect inflation from 1992 to 2008." (Chernick Dir. 22:500-501) Inflation is part of the problem that affects both NPC and non-NPC and it is not necessarily the case that it should be ignored. Mr. Chernick also argues that costs per kWh should be used—but again, this would affect both NPC and non-fuel costs. Finally, Mr. Chernick claims that we must look at the revenue side of the equation by somehow factoring in the evaluation of expenses, revenue changes as a result of rate cases. This mixing of the revenue and expenses, as Mr. Chernick suggests, would blur the question of expense volatility and not answer the fundamental question as to whether NPC are volatile.

Q. Please discuss the volatility of spot market prices.

A. Coal, gas, and wholesale electricity costs are volatile, as shown in

A. **Figure** 2. Mr. Chernick characterizes Uinta and Rockies as the "least-expensive and least-volatile regions" (Chernick Dir. 24:560-562).

A. **Figure** 2 shows, very graphically, that there has been substantial volatility in coal prices at both Uinta and the Powder River Basin during the past three years.[10] The same can also be said for gas and wholesale power costs. And, spot prices *are* relevant—not all spot market risk can be hedged away. Fuel is a large, volatile expense for PacifiCorp. Moreover, the majority of NPC come from coal, which may face increasing volatility in the future.[11]

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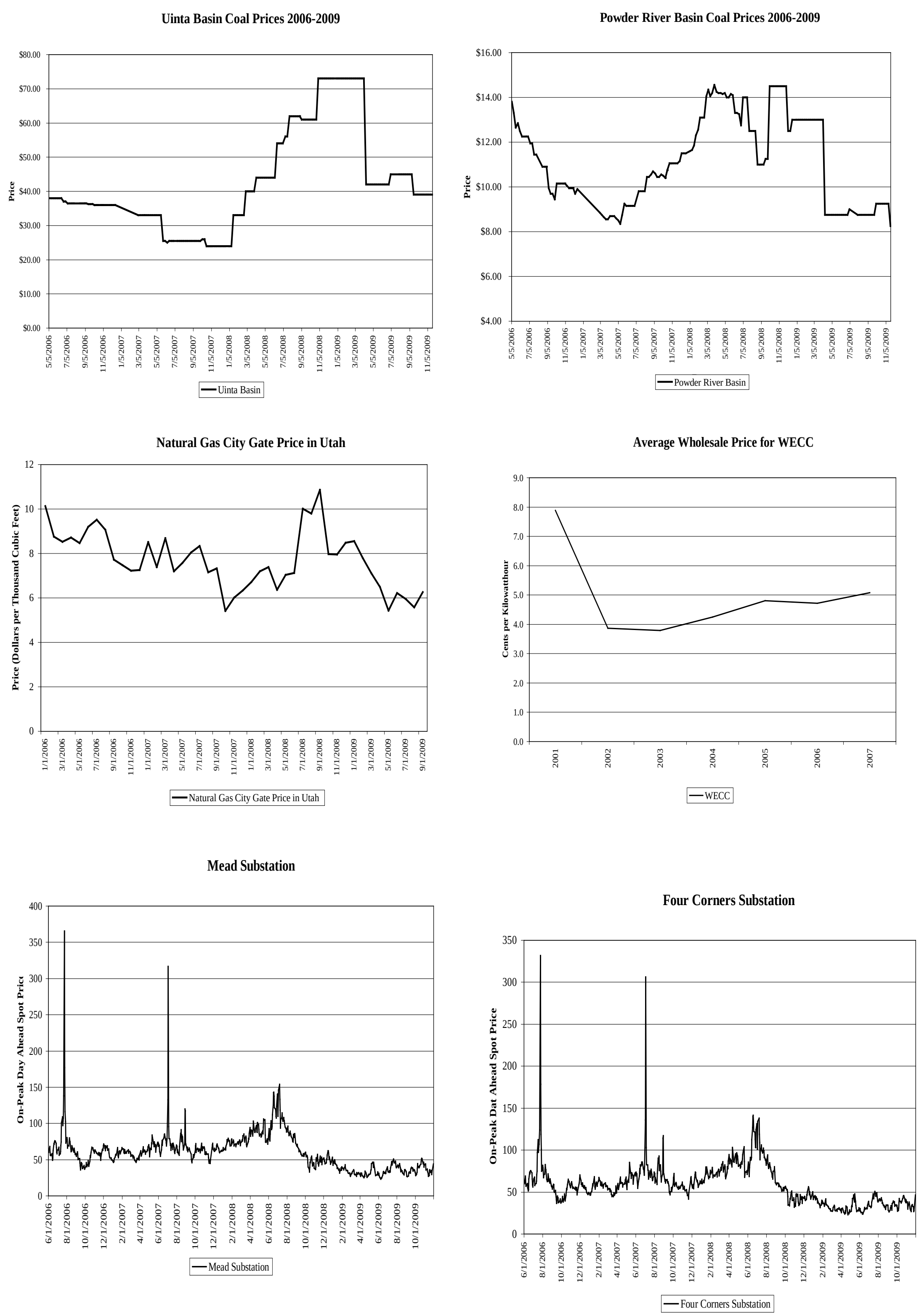
[10] This is corroborated by the fact that utilities in the Rockies, such as Xcel's Colorado operations, have ECAM mechanisms in place. The fuel clause in Colorado is referred to as the Electric Commodity Adjustment. http://xcelenergy.com/Colorado/Company/About_Energy_and_Rates/Energy%20Prices%20%28Rates%20and%20Tariffs%29/Pages/Colorado_Electric_Commodity_Adjustment.aspx. Accessed December 5, 2009.

[11] In June 2008, WRA produced a white paper demonstrating that coal prices in the spot market have been more volatile than natural gas prices, primarily because of increased foreign demand for domestic coal supplies. (Kelly Dir., 1:13-15)

Figure 2: Coal, Natural Gas, and Wholesale Electricity Prices



Q. Please describe the effect forecasting will have on an ECAM.

A. Mr. Chernick argues that "RMP has not demonstrated that the commodity price forecasts used in developing the NPCs for various years were incorrect." Mr. Gregory N. Duvall's Exhibit RMP___(GND-1R) shows that the commodity price forecasts used to set NPC turned out to be incorrect by $10 to negative $25 per MWh when compared to actual commodity prices over the last eight years. In fact, there was no instance where the forecast was correct during that period. While it is unclear exactly why this turned out to be the case, one might conclude that the ordinary ratemaking process absent an ECAM—with the commodity prices frozen for setting rates, while actual commodity prices fluctuate daily—might best be supplanted by an approach that provides an assurance that ratepayers pay rates that reflect the actual cost of supplying electricity.

Professor Alfred E. Kahn wrote in 1975 on the topic of forecasting absent the fuel adjustment clause:

> Without a fuel adjustment clause, the Commission would be forced literally to guess what the average cost of fuel will be for at least a year into the future in setting rates. This would require a prognostication not only of what fuel suppliers will charge […] but also what proportion of the time the company will use each of its various generating units to supply electricity.
>
> Without a fuel adjustment clause, we would have to make those predictions in arriving at a best guess of the future average cost of fuel. And if we were markedly—or even only moderately off—in either direction, the consumer would suffer. He would obviously suffer if we estimate too high. What is doubtless less obvious, he would suffer also if our allowance for fuel expenses was substantially too low: in that event the financial condition of the utility could erode very quickly, and with very little lead time jeopardize its ability to raise the capital necessary to provide consumers with good service, on reasonable terms.[12]

[12] Statement of Alfred E. Kahn, Chairman, New York State Public Service Commission, On Fuel and Gas Adjustment Clause, October 22, 1975, pp. 3-4.

Q. Mr. Chernick asserts that the volatility of fuel prices is irrelevant while the differential between the forecasted gas prices and the actual spot price should be the focus of the ECAM. (Chernick Dir. 9:210-216) What is your response?

A. The distinction between the actual spot price at a given time in the future and the forecasted price for that period developed by PacifiCorp warrants discussion. The accuracy of historical predictions does not change the volatility underlying the commodities in question. With regard to the issue of volatility, it is irrelevant whether historical gas forecasts have been accurate. Furthermore, even if past forecasts had been accurate, which they clearly have not, that does not necessarily mean that they continue to be capable of accurate prediction. As investment managers constantly remind us, past performance does not predict future performance. An ECAM would allow the actual price of the commodity to be reflected in rates, allowing the customer to adapt their usage accordingly. This is not to say the ECAM would usher in real-time pricing; however, an ECAM gives consumers a greater price signal than if the costs were simply rolled into standard rate cases. An ECAM would allow Rocky Mountain Power to cover its reasonable and prudently incurred costs.

Q. Please describe how Rocky Mountain Power's hedging policy effects the proposed ECAM.

A. In essence, the intervenors argue that because Rocky Mountain Power hedges its fuel costs, its NPC are not volatile enough to justify an ECAM. However, mitigating volatility has an ex ante cost relative to not hedging, i.e., an "insurance premium" is paid. While hedging reduces the volatility of fuel costs, it must be considered in the context of a tradeoff between reduced volatility and higher ex-ante fuel costs (given the uncertain nature of the reduced volatility to customers). A report from the National Regulatory Research Institute notes that:

> [U]tility hedging adds another complicating dimension. How much a utility ought to hedge depends on the value placed by customers on more stable prices—a value difficult to determine. Hedging requires a trade-off between the objectives of moderating price volatility and passing through to customers the lowest cost for purchased gas. Utilities and commissions face the challenge of deciding precisely how much a utility should hedge, how it should hedge, and how much it should spend on hedging. Customer tolerance of price volatility will vary among customers and between classes. Because of these complications, early commission involvement will help determine the utility's hedging parameters. Otherwise the utility has to guess about customer preferences and then risk disallowance later if it guessed wrong—such as if the rates underlying the selected hedge strategy exceed the prevailing price for spot gas. A commission can provide a utility with at least a broad indication of the level of tolerable price volatility or, conversely, the insurance premium charged to customers it will find acceptable.[13]

B. BEYOND THE CONTROL OF THE UTILITY

Q. Is the price of fuel and power beyond the control of the utility?

A. Yes. The intervenors have misstated the "beyond the control of a utility" criteria. The utility has to procure resources (such as fuel) and make sales for resale prudently, but the prices are set in markets over which the utility has no control. Prices in wholesale fuel markets are entirely outside the control of the utility and the quantities used are based on the prudent operation of the system (over which the Commission will continue to have oversight, as it always has). Rocky Mountain Power's obligation to justify the reasonableness of its costs to its regulator gives it an incentive to continue to procure resources prudently,

[13] National Regulatory Research Institute (Ken Costello), *"Gas Supply Planning and Procurement: A Comprehensive Regulatory Approach,"* June 2008, p. 2.

recognizing that it is but one of many entities that procure fuel from markets and therefore cannot control the *price* of fuel.

Just as "exogenous costs" in price-cap mechanisms pass through costs that are beyond the control of the utility without damaging incentives, so too can the *price* of fuel and power be said to be beyond the control of the utility. Rocky Mountain Power will still have direct economic, as well as regulatory, incentives to acquire coal efficiently. Further, an ECAM would allow quicker pass-through of any *decreases* in fuel costs, in the form of savings to end-use customers, something neither irrelevant nor inconsequential given recent trends in natural gas prices. These aspects and the other incentives I have noted earlier relating to the proposed ECAM should not be overlooked.

III. ECAM AND INCENTIVES

Q. What issue do you address in this section?

A. Several intervenors have claimed that an ECAM distorts incentives or provides poor incentives for efficiency. (Chernick Dir., 35:841-953; Higgins Dir., 7:132-135; SLCAP Exhibit 1.0, 6:1-4; Kelly Dir.)

A. INCENTIVE ISSUES

Q. What are the issues raised by the intervenors?

A. There seem to be three distinct concerns about incentives. First, there is a concern over the operational incentives. Second, there is a concern that short-term operational incentives will affect long-term resource procurement. Finally, there is a concern that an ECAM will produce a bias against renewable and energy efficiency. I will address the first issue in this section of my testimony. The second issue is addressed later in this testimony. The third issue is addressed by Mr. Duvall. (Duvall Reb.)

Q. How do you respond to the issue of operational efficiency?

A. First, let me reiterate my position from my supplemental direct testimony. There is no direct evidence that an ECAM, as proposed in this case, which includes a prudence review, will *necessarily* distort the utility's incentives relative to the current rate of return approach. As proof, I cited the fact that few, if any, regulators have removed such programs as a result of this alleged inefficiency bias. Mr. Chernick, however, takes issue with my conclusion and cites a litany of academic studies that purport to show the incentive problem. We need to be clear about exactly what Mr. Chernick's studies indicate. He first cites Alfred E. Kahn for the proposition that regulatory lag is a meaningful incentive. I have no disagreement that regulatory lag provides meaningful incentives to control costs, in the areas that Kahn notes. Those areas are all ones where the utility has significant control over the outcomes; this is largely not the case with fuel costs. More importantly, when Professor Kahn, then Chairman Kahn, was faced with the same questions raised by this proceeding at the New York Public Service Commission, he defended the use of ECAMs as a necessary and important regulatory mechanism. While Chairman Kahn notes the lack of incentives in a truly automatic pass-through mechanism, he identifies the regulatory lag, even 30 to 60 days, as being an important factor counteracting the alleged disincentives.[14] Kahn also notes that the alternatives to ECAMs are limited. I concur with this

[14] Kahn, *supra* note 12.

conclusion, and despite our wish for a better solution, after many years of searching, such a solution has not yet been found.

Further, Mr. Chernick's interpretation of the economic literature does not comport with how economists view the literature. Economists view the literature as far less certain than Mr. Chernick does, due to the offsetting efficiency effects of rate or return regulation that is said to bias firms toward too much capital, and a fuel adjustment charge which is said to bias firms toward too much fuel intensive production. Indeed, Atkinson and Halvorson (1982) make this point which appears lost in Mr. Chernick's translation (despite the conclusions from the study). Furthermore, Mr. Chernick neglects to mention that the input bias effect is often related to ECAMs that do not have a formal hearing process associated with the mechanism. As I understand the ECAM process in Utah, it would have a formal prudence review. Indeed, even Mr. Chernick's own testimony cites this as a factor:

> In short, firms face reduced financial punishment if inefficient production methods are adopted….regulatory lag and formal hearings play an important efficiency inducing role. (Gollop and Karlson cited by Chernick Dir., 36:865-867)

Other economists are reluctant to throw ECAMs out as a viable tool to regulate utilities due to potential benefits. For example, Mr. Chernick cites the work of Kasermen and Tepel (1982). These authors end their study by concluding:

> [T]he automatic fuel adjustment clause carries with it certain benefits. These consist primarily of resource savings from conserving on rate hearings and preservation of the utility industry's ability to attract capital investment. It is our recognition of such unmeasured benefits that prevents us from drawing more sweeping public policy implications from our study results. (Id. p. 700)

Other studies cited by Mr. Chernick relate not to the fuel adjustment clause per se, but to the greater levels of efficiency related to alternatives to traditional regulation, including fuel pass through charges, (e.g., Knittle and Fabrizio et. al.). In sum, Mr. Chernick's citation of studies from the academic literature does not show that any particular ECAM will necessarily distort input choices in a manner that reduces overall efficiency. Further, if we are concerned about efficiency because of its relationship to prices, then the costs of hedging with and without an ECAM must be taken into account. It is not at all clear that any of the studies Mr. Chernick cites attempts to take this into account. My initial conclusion remains, despite the theoretical ambiguity of the efficiency effect, that if the Commission, finds evidence that this particular ECAM in the future, or more accurately the ECAM approved by the Commission, causes input bias, then it may adjust the design of the ECAM to address this issue. Therefore, the incentive issue is, in its essence, an empirical issue and therefore a design issue.

B. COMPREHENSIVE TREATMENT OF NET POWER COSTS

Q. Please discuss the comprehensive treatment of net power costs.

A. At the outset, I note that this issue overlaps substantially with the issues to be considered in the design phase of this proceeding. Nonetheless, because the intervenors have given considerable attention to this issue in the context of their arguments that an ECAM is not in the public interest because it would affect utility incentives, I refute various arguments for asymmetric (i.e., non-comprehensive) treatment of individual categories of net power costs, discuss the problems with such asymmetric treatment from a resource-planning perspective, and briefly touch on some issues with respect to gas-related hedging. I respond in turn to the issues raised by WRA witness Ms. Kelly,[15] UAE witness Mr. Higgins,[16] OCS witness Ms. Beck,[17] and DPU witness Mr. Peterson.[18] Please note that the "comprehensive treatment" issues, to the extent they are incentive issues, are related to issues already addressed in this testimony—notably whether net power costs are large, volatile, and beyond the control of the utility—and therefore I do not address these issues in great detail here.

ECAMs are designed to be comprehensive, i.e., all relevant costs related to fuel and purchased energy are recovered on a level playing field. Typically, costs related to fuel, purchased energy, fuel transportation, hedging, and emissions allowances are the primary categories. The reason for this is simple: if some costs were treated one way, and other costs another, perverse incentives could be created. Comprehensive and symmetrical treatment provides an assurance that fuel and purchased energy are treated equally, meaning that a utility would not have an incentive to favor one over the other.

[15] WRA witness Ms. Kelly raises a concern about the "incentives and disincentives that an ECAM creates for long-run resource acquisition." (Kelly Dir. 2: 20 and 3:4)

[16] UAE witness Mr. Higgins argues that "an ECAM could pass through cost that are not associated with price volatility…. Such costs are most appropriately recovered pursuant to a general rate case rather than a single issue proceeding. He also states that a concern about Rocky Mountain Power changing its hedging policy in a manner that would "increase the pricing risk to customers." (Higgins Dir. 17:356-362)

[17] OCS witness Ms. Beck identifies the ratemaking treatment of gas hedging-related costs and electricity market energy costs as "threshold" issues" and states that "[o]ne could conceive of a multi-tiered design in which different price caps or overall percentages of market costs were allowed" but then goes on to state that it is not "realistic to assume that ECAM design could remedy the problems associated with over-reliance on the market." (Beck Dir. 11:223-334)

[18] DPU witness Mr. Peterson states that "some of the qualifications or conditions the Division would expect" of an ECAM would include, among other items, that the ECAM mechanism "only cover those costs that are truly outside of Company control and cannot be anticipated and/or significantly mitigated." Mr. Peterson goes on to discuss a "breakdown of items that could be included." (DPU Phase I Exhibit 1.0, 18: 389-390, 19: 424-510)

Q. Please respond to the relevant issues raised by WRA witness Ms. Kelly.

A. Ms. Kelly is concerned that an ECAM would distort Rocky Mountain Power's incentives and disincentives with respect to long-run resource acquisition. Simply put, comprehensive treatment of NPC provides proper incentives to the utility. I will begin by providing a simple explanation of why comprehensive treatment of NPC is necessary.

Any electric utility has two primary categories of costs. The first category is related to the utility's long-lived assets and the myriad of costs related to operating its business, which can usefully be addressed through the base rate case ratemaking process or through single-item rate cases for major plant additions. The second category has to do with net power costs, which are normally recovered through an ECAM, so long as these costs, as a whole, are found to be large, volatile, and beyond the control of the utility. I see no reason why this approach would be harmful from a resource-planning perspective relative to the status quo approach of dealing with NPC in base rate case proceedings—this is because the utility's incentives to procure least-cost resources would be unchanged. Rocky Mountain Power would, in either case, strive to avoid prudence-related disallowances, which would lead it to have the proper incentives to procure resources on a least-cost basis.

Although this question should more appropriately be addressed in Phase II, it is the case that NPC are recovered comprehensively because of the distortions that could be presented if they were not treated that way. A few examples would include:

- Fuel and purchased energy are treated identically because to do otherwise might give a utility a reason to favor one over the other, rather than focusing on using the least-cost resources available at any given time.

- Fuel and fuel transportation costs are treated on a level playing field because to do otherwise might favor more-costly but near-at-hand resources over more distant resources that nevertheless have a lower delivered cost.

- The fuel costs that are recovered would be the actual costs including any hedging-related costs and benefits that have been incurred. Thus, if hedging of natural gas costs is done, the relevant costs would be the actual ex post costs that reflect the outcomes of the hedging transactions. Given that the utility would only hedge if it saw that customers value a reduction in the volatility of the cost of electricity service, it would not make sense, for example, to pass through the gas costs that would have been the case if hedging had not been pursued (keeping in mind that on an ex ante basis, hedging would be expected, on balance, to increase the cost of electricity for the customer).

Rather than harming incentives, the combination of an ECAM and the standard base rate case process provides a rational, incentive-based means of recovering net power costs. Non-comprehensive treatment of categories of NPC would, on the other hand, raise a myriad of concerns.

Q. Please respond to the issues raised by Mr. Higgins. (Higgins Dir. 17: 356-362)

A. Mr. Higgins raises three issues:

- *An ECAM would pass through NPC that are not necessarily associated with price volatility.* As discussed above, all NPC should be recovered on a level playing field. This is proper and necessary.

- *BPA transmission charges would be recovered in the same way as other types of net power costs*. The relevant wholesale power costs would include the costs of delivering that power to Rocky Mountain Power's grid. Again, this is proper and necessary, as discussed previously.

- *Rocky Mountain Power could change its hedging policy in a manner that would increase the pricing risk to customers*. The Commission would continue to scrutinize the Company's hedging policy as it scrutinizes other categories of net power costs.

Q. Please respond to the issues raised by OCS witness Ms. Beck.

A. Ms. Beck identifies the ratemaking treatment of gas hedging-related costs and electricity market energy costs as "threshold" issues. As discussed above, gas costs and market electricity costs should be treated on a level playing field with other categories of net power costs.

C. THE RISK SHARING "STRAW MAN"

Q. How do you respond to the issue that an ECAM shifts the risk of NPC to consumers?

A. I refute the "straw man" argument, made by OCS witness Ms. Beck,[19] UAE witness Mr. Higgins,[20] and DPU witness Mr. Peterson,[21] that the ECAM would somehow shift risk from utility shareholders to customers.

In my view, arguing about risk shifting is a fruitless endeavor; essentially all electric utilities in traditionally-regulated states are allowed to utilize this reasonable ratemaking process**.** The risk sharing straw man is just that, a decoy or red herring, that adds nothing to the debate about whether an ECAM is in the public interest.

Q. Why do you call the risk shifting argument a "straw man"?

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[19] OCS witness Ms. Beck raises "concerns relating to the shifting of risk from utility management to customers" and erroneously argues that the ECAM would shift risk of fluctuating NPC onto "customers who have no input on management's business decisions." (Beck Dir. 6: 117-118 and 137)

[20] UAE witness Mr. Higgins argues that "ECAMs shift risks from utilities to customers." He further states that these risks include price risk, resource portfolio risk, weather-related risk, forced outage risk. (Higgins Dir. 7: 135-139)

[21] DPU witness Mr. Peterson states that "the proposed ECAM shifts too much risk from Rocky Mountain Power to ratepayers," and suggests that Rocky Mountain Power wants ratepayers to "step up" and assume risks that Rocky Mountain Power is in the "best position to manage and mitigate," and states that "mechanisms that share risk could, potentially, be in the public interest." (DPU Phase I Exhibit 1.0, 5: 107-108, 24: 25: 551-554, and 25: 570-571)

A. The argument is a red herring for the real issue, which is that customers should pay rates that reflect the cost of providing the service they receive. Webster's defines "straw man" as an "argument or opponent set up so as to be easily refuted or defeated."[22] The risk shifting argument, which is a familiar regulatory topic,[23] is a distraction or decoy that cannot withstand careful scrutiny and should be rejected by the Commission.

Q. How do you refute the risk shifting argument?

A. First, utility ratepayers can reasonably be expected to pay just-and-reasonable rates that provide a utility with a reasonable opportunity to recover its prudently-incurred costs. In conjunction with the base rate case process, an ECAM that is designed and implemented in an appropriate manner is fully consistent with this principle. Mr. Duvall shows in his rebuttal testimony that over the last eight years, the practice of collecting net power costs through the base rate case process in Utah has failed because Utah customers have underpaid prudently-incurred NPC by over $300 million. (Duvall, Reb.) Calling this risk shifting is, at best, misleading and distracting.

Second, it is not at all clear what the proponents of "risk shifting" mean when they use the term "risk." Risk, when used loosely, is a nebulous, imprecise term. It is fair to say that the term "risk" has not been defined carefully in the testimony that I am responding to and thus the meaning is in the eye of the beholder. The

[22] *Webster's II: New College Dictionary*, p. 1090.

[23] See: Jeff D. Makholm, "The Risk Sharing Strawman," *Public Utilities Fortnightly*, July 7, 1988, pp. 24-29.

business and financial risk borne by investors can be defined rigorously, but the risk borne by ratepayers is an entirely different concept.

Third, risk shifting can amount to cost shifting. As an economist, I prefer to analyze *cost*, which is a much more concrete concept than risk—costs can be measured, verified, and classified. The same cannot be said about the "risk" that is applicable to the "sharing" of risk between ratepayers and investors. An ECAM, such as that proposed by Rocky Mountain Power, reconciles the cost of fuel and purchased energy initially included in rates, with the actual, after-the-fact cost of those items, so there is an assurance that ratepayers are paying a just and reasonable rate that reflects the cost of service. In contrast, the absence of an ECAM leads to the over- or under-recovery of net power costs. It would appear, given the difficulties associated with setting rates based on forecasted net power costs, that there would likely always be significant gaps between forecasted NPC paid by ratepayers and the actual NPC borne by Rocky Mountain Power's investors. Most states have ECAMs—thereby avoiding problems related to the over- or under-recovery of net power costs.

Q. Do you have comments on the specific types of risk identified by UAE witness Mr. Higgins?

A. Yes. Mr. Higgins raises issues with respect to price risk, weather-related risk, resource portfolio risk, and forced outage risk. I address these topics in turn.

- *Price risk*. Elsewhere in this testimony, I explain that given that the *price* of power is beyond a utility's control (given that it is a price-taker in power markets), there is no reason to not pass through the cost of fuel to ratepayers.

- *Resource portfolio risk*. UAE witness Mr. Higgins argues (Higgins Dir. 18: 377-385) against transferring the risk/benefit of hydro availability to Rocky Mountain Power's ratepayers. But, Rocky Mountain Power has no control over the availability of hydro-electric power, and therefore shifting the over- or under-recovery of hydro-related costs to ratepayers cannot affect the utility's incentives in any way.

- *Forced outage risk.* UAE witness Mr. Higgins states that forced outages would "automatically" pass through to customers. Fuel costs would not be passed through "automatically" under the proposed ECAM, but would always be subject to review by regulators and Commission approval. In fact, in states where ECAMs are in place, regulators frequently review utilities' actions for prudence and, when a regulator finds that an imprudent action led to unreasonable replacement power costs, have disallowed the imprudently-incurred costs. Issues related to forced outages resulting from imprudent operation of a generating unit can readily be dealt with by state utility regulators, whether or not an ECAM is in place. A utility's incentives to avoid disallowances based on imprudence remain squarely in place.

Q. How would you respond to the suggestion that an ECAM that provides only partial pass through of NPC can be a way to share risk?

A. These issues are largely an issue for the "design" phase. Nevertheless, I would question whether those types of mechanisms serve any useful purpose. DPU witness Mr. Peterson states that "mechanisms that share risk could, potentially, be in the public interest." (Peterson Dir. 25: 570-571) It is hard to argue with this since it is not clear what mechanisms Mr. Peterson has in mind. As a general matter, as I discuss elsewhere in this testimony, I would be skeptical of approaches such as "95/5 sharing" (as used in Missouri) except as a way to gain experience with the implications of moving to a dollar-for-dollar ECAM.

Jurisdictions with partial pass through in an ECAM blur the distinction between risk sharing for productive purposes and risk sharing in the price-taking purchase of inputs. In other words, some jurisdictions impose risk sharing on the price of fuel and purchased power. These cases are idiosyncratic and have generally been a phase in a broad movement toward the full pass-through of fuel and power purchases. Idaho, for example, has moved, over time, to fuller pass through of power costs. For example, prior to 1993, Idaho Power absorbed all fuel cost changes between rate cases, 40 percent from 1993 to 1995, 10 percent from 1995 to early-2009, and only five percent thereafter.[24] This represents an example of the movement towards full pass through of power costs. In any event, these are issues that need not be resolved in this Phase I.

IV. REGULATORY SCRUTINY AND WHAT OTHER JURISDICTIONS DO

Q. What do you think of the "regulatory scrutiny" issue?

A. It is another red herring. States that use ECAMs find ways to integrate prudence oversight into the regulatory process. It is also clear that essentially all U.S. utilities have an ECAM that is consistent with my basic understanding of what an ECAM is intended to accomplish.

A. SURVEY OF REGULATORY PRACTICE

Q. Is regulatory practice in other jurisdictions relevant here?

A. Yes. Mr. Chernick notes that:

> Despite its reliance on practice in other jurisdictions, Rocky Mountain Power was unable to describe the mechanisms, in terms of the share of costs flowed through the mechanism, adjustment caps and dead bands, generator performance requirements, categories on costs included, and whether the adjustment is based on actual fuel prices or market indices (DR OCS 2.66). (Chernick Dir. 48: 1171-1175)

In Exhibit RMP___(KAM-1R), I provide comprehensive information on three key characteristics of ECAM mechanisms: use of projected or historic fuel costs in the

[24] Before the Idaho Public Utilities Commission, *In the Matter of Idaho Power Company's Petition for Approval of Changes to its Power Cost Adjustment Mechanism.* Case No. IPC-E-08-19. Order No. 30715, January 9, 2009.

initial month, whether true-up/balancing mechanisms are used to reconcile the power costs in rates with actual power costs, and the length of the reconciliation period. The Utah Commission will need to evaluate the evidence before it, just as these other state commissions have done, and determine what is in the best interests of the public and its utilities. I conclude, however, that Rocky Mountain Power's proposal is squarely within the mainstream practice with respect to these three characteristics of ECAM mechanisms. However, as noted above, the precise design of Rocky Mountain Power's ECAM is not at issue in this phase of this proceeding.

Mr. Chernick specifically referred to the ECAMs in Wisconsin and Vermont. (Chernick Dir, 49:1190-1204) It is clear that Wisconsin currently has a mechanism in place where the initial month's rates are based on a projection, but if there is an over- or under-collection of actual costs (beyond a "variance range") there is a reconciliation process; moreover, the Wisconsin legislature is currently considering legislation that would amend Wisconsin's ECAM approach to be more comparable to those in other states.[25] Mr. Chernick also mentions Vermont. It may be true that Vermont approved ECAMs as part of the resolution of a more comprehensive set of issues, but that does not change the fact that Vermont is now squarely in the mainstream of regulatory practice with respect to ECAMs.

Some intervenors have raised concerns that Rocky Mountain Power's proposed ECAM would somehow blur the "price signal" seen by end-use customers. Due to the persistent under forecasting of NPC, customers currently are not seeing a price

[25] *2009 Assembly Bill 600*. An act amending the current fuel clause mechanisms in place, November 24, 2009.

signal that is at all accurate. Any reconciliation period that takes place more often than a traditional rate case would provide a better price signal than the ratemaking that is currently in place. From this standpoint, a one-month or three-month reconciliation period would be preferable, but any ECAM design would provide a more accurate matching of costs and revenues providing better signals about the cost of consuming electricity compared to the current, and consistent, under charging for electricity. As mentioned elsewhere, the details of ECAM design can be left to the design phase.

Exhibit RMP___(KAM-2R) provides examples of state regulatory practices with respect to the share of costs flowed through the mechanism, adjustment caps and dead bands, and generator performance requirements. Of the 95 companies I reviewed, 78 use projected net power costs for the initial rate period and 93 have some form of reconciliation (true-up) or balancing account mechanism. The reconciliation period varies between one and twelve months, with 39 having a reconciliation period of six months or less, although the majority of the companies (52 of 95) have a twelve-month reconciliation period. I provided a survey of the categories on costs typically included in ECAMs in other jurisdictions as part of my direct testimony, so I will not re-do that survey here.

B. REGULATORY OVERSIGHT OF PRUDENCE

Q. Please describe how other jurisdictions go about overseeing prudence.

A. Regulatory oversight of the prudence of a utility's management of its power procurement activities and the performance of the utility's generation plants can be accomplished while allowing for timely rate changes that reflect fuel and wholesale power market prices accurately. Many states have developed means, such as periodic reviews, to provide a forum to discuss any prudence issues that may arise. It is frequently the case that states which allow for fuel cost adjustments also require some form of reporting to the public utility commission as well as a public hearing or audit. States typically require that utility ECAMs include public filings or hearings for increases on an established frequency. For example, the Minnesota Public Utility Commission requires an annual report that reviews the accuracy and prudence of its ECAM.[26]

One straight forward way to show that states with ECAMs can oversee prudence is to summarize some of the disallowances that have been made. **Table 1** shows that it is not unusual for regulators to disallow net power costs based on imprudence. In the absence of competitive forces, regulators must be charged with ensuring that costs imposed on consumers are prudently incurred and approximate those that would occur in a competitive market.

Many instances of prudence investigations in fuel cost adjustment mechanisms occur when utilities were forced to purchase more expensive power on the wholesale market as a result of a plant outage. For the utility to recover its costs: "[t]he company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions

[26] Minnesota Rule 7825.2810: Annual Report; Automatic Adjustment. *See*: http://www.revisor.leg.state.mn.us/arule/7825/2810.html (accessed on December 5, 2009).

were made."[27] Commissions investigate the costs that are reflected in the fuel cost adjustment tariffs. Below is a list of current or recently concluded state commission investigations of prudence of costs recovered in an ECAM or PGA.

[27] Washington Utilities & Transportation Commission, RE: Puget Sound Power & Light Co., 156 PUR4th 297, 303(Wash UTC, 1994) as cited in Goodman, Leonard S. "The Process of Ratemaking" Vol.II, pp. 881-2.

Table 1: Investigations & Decisions Regarding Prudence

State	Company	Date	Description	Reference
OH	Vectren Delivery of Ohio	6/14/2005	Ohio PUC denied VDO recovery of gas-related costs following a management/performance audit of the Company. The PUC indicated that the contract between Vectren and ProLiance was not at arms length, and that Vectren had no intention of awarding this asset management contract to an unaffiliated third-party. The Commission concluded improprieties occurred concerning the right to utilize unused gas transportation capacity, costs related to an unnecessarily high gas reserve margin and costs related to the treatment of interstate pipeline refunds.	Case No. 02-220-GA-GCR
TX	CenterPoint Energy Houston Electric	5/27/2004	Texas PUC precluded capacity costs from being recovered under fuel adjustment clauses, the CenterPoint contract had "an implicit capacity component because they had capacity attributes of reliability and firmness of supply and were used to meet Centerpoint's load obligations without increasing its generating capacity."	Docket No. 26195
WA	Puget Sound Energy	5/13/2004	WUTC established guidelines for recovery of costs associated with the Company's long-term wholesale contract to purchase power from the Tenaska plant. The WUTC also found that the Company did not, prior to the implementation of the PCA, adequately manage its fuel-cost risks and therefore ordered the Company to adjust its power cost adjustment deferral account to reflect the imprudent management.	Docket No. 031725
NJ	Elizabethtown Gas	5/14/2004	Settlement reached in an audit into company misconduct related to the Company's power procurement practices: management failed to adequately consider the risks associated with its growth strategy, and had improperly utilized the financially healthy utility operations to support failing non-utility activities.	Docket No. GA03030213
NV	Nevada Power Company	3/24/2004	The PUC authorized NPC recovery of $169 million of a requested $173 million of deferred energy costs as part of an application to recover fuel and purchased power costs as well as to adjust the prospective rate for fuel and purchased power.	Docket 03-11019
TX	El Paso Electric	5/5/2004	Reversed a decision allowing energy-only purchased power contracts to be recovered which had been previously disallowed as capacity costs. Did not reverse other findings that other contracts did not contain capacity costs.	Docket No. 26194
NY		2/11/2004	A settlement disallowed the recoupment of costs of replacement power associated with power plant outages that were, in the Staff's view "could have and should have been either avoided or reduced in duration; but it also notes that its position includes a significant degree of uncertainty."	Case No. 00-E-0612

Q. Does this conclude your rebuttal testimony?

A. Yes.