Gary A. Dodge, #0897
Hatch, James & Dodge
10 West Broadway, Suite 400
Salt Lake City, UT 84101
Telephone: 801-363-6363
Facsimile: 801-363-6666
Email: gdodge@hjdlaw.com

Attorneys for Utah Association of Energy Users

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of Its Proposed Energy Cost Adjustment Mechanism	**Docket No. 09-035-15**

PREFILED DIRECT TESTIMONY OF KEVIN C. HIGGINS

PHASE I

The Utah Association of Energy Users ("UAE") hereby submits the Prefiled Direct Testimony of Kevin C. Higgins in this docket on Phase I policy issues.

DATED this 16th day of November, 2009.

/s/ ______________________________
Gary A. Dodge,
Attorneys for UAE

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served by email this 16th day of November, 2009, on the following:

Mark C. Moench
Yvonne R. Hogle
Daniel E. Solander
Rocky Mountain Power
201 South Main Street, Suite 2300
Salt Lake City, Utah 84111
mark.moench@pacificorp.com
yvonne.hogle@pacificorp.com
daniel.solander@pacificorp.com

Michael Ginsberg
Patricia Schmid
Assistant Attorney General
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84111
mginsberg@utah.gov
pschmid@utah.gov

Paul Proctor
Assistant Attorney General
160 East 300 South, 5th Floor
Salt Lake City, UT 84111
pproctor@utah.gov

F. Robert Reeder
William J. Evans
Vicki M. Baldwin
Parsons Behle & Latimer
One Utah Center, Suite 1800
201 S Main St.
Salt Lake City, UT 84111
BobReeder@pblutah.com
BEvans@pblutah.com
VBaldwin@pblutah.com

Arthur F. Sandack
8 East Broadway, Ste 510
Salt Lake City, Utah 84111
asandack@msn.com

Peter J. Mattheis
Eric J. Lacey
Brickfield, Burchette, Ritts & Stone, P.C.
1025 Thomas Jefferson Street, N.W.
800 West Tower
Washington, D.C. 20007
pjm@bbrslaw.com
elacey@bbrslaw.com

Gerald H. Kinghorn
Jeremy R. Cook
Parsons Kinghorn Harris, P.C.
111 East Broadway, 11th Floor
Salt Lake City, UT 84111
ghk@pkhlawyers.com
jrc@pkhlawyers.com

Steven S. Michel
Western Resource Advocates
227 East Palace Avenue, Suite M
Santa Fe, NM 87501
smichel@westernresources.org

Michael L. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
mkurtz@bkllawfirm.com
kboehm@bkllawfirm.com

Betsy Wolf
Salt Lake Community Action Program
764 South 200 West
Salt Lake City, Utah 84101
bwolf@slcap.org

Holly Rachel Smith, Esq.
Russell W. Ray, PLLC
6212-A Old Franconia Road
Alexandria, VA 22310
holly@raysmithlaw.com

Sarah Wright
Utah Clean Energy
1014 2nd Avenue
Salt Lake City, UT 84103
sarah@utahcleanenergy.org

Mr. Ryan L. Kelly
Kelly & Bramwell, PC
11576 South State Street Bldg. 203
Draper, UT 84020
ryan@kellybramwell.com

/s/ ______________________

BEFORE

THE PUBLIC SERVICE COMMISSION OF UTAH

Direct Testimony of Kevin C. Higgins

on behalf of

UAE

Docket No. 09-035-15

Phase I

November 16, 2009

DIRECT TESTIMONY OF KEVIN C. HIGGINS

Introduction

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by the Utah Association of Energy Users ("UAE").

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before this Commission?

A. Yes. Since 1984, I have testified in twenty-four dockets before the Utah Public Service Commission on electricity and natural gas matters.

Q. Have you testified previously before any other state utility regulatory commissions?

A. Yes. I have testified in over one hundred other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Arizona, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings at the Federal Energy Regulatory Commission.

A more detailed description of my qualifications is contained in Attachment A, attached to this direct testimony.

OVERVIEW AND CONCLUSIONS

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

A. My testimony addresses the Phase I threshold and policy issues regarding the need for an Energy Cost Adjustment Mechanism ("ECAM") for Rocky Mountain Power ("RMP") in the State of Utah.

Q. What are your primary conclusions and recommendations regarding the adoption of an ECAM in the RMP Utah jurisdiction?

A. I do not believe that adoption of an ECAM for RMP in Utah is in the public interest in light of all relevant considerations. An ECAM is a form of single-issue ratemaking, and should only be applied after carefully weighing the justification for such an approach against its several drawbacks. Some of these drawbacks include reduced incentives for management to control costs, the shifting of risk from the utility to customers, and reduced economic incentives for the utility to undertake demand-side management actions.

In my opinion, an ECAM should not be considered unless the costs that would be recovered through an ECAM are subject to significant volatility, are largely beyond the control of management, and are substantial enough to have a material impact on the utility's revenue requirement and financial health between rate cases if they were to go unrecovered.

Based on the Company's fuel mix and hedging practices, I conclude that RMP's cost structure is not sufficiently volatile to justify adoption of an ECAM at this time. Moreover, a future test period, which is being used by stipulation in

RMP's current rate case in Utah, when taken in combination with RMP's aggressive hedging practices and frequent rate case filings, further diminishes any need or justification for an ECAM in Utah at this time.

DISCUSSION OF ISSUES

Q. What is the basic principle behind the operation of an ECAM?

A. Generally, an ECAM identifies a base level of fuel and purchased power costs that are included in current rates. When going-forward fuel and purchased power costs deviate from the base level, an ECAM can provide an adjustor charge to recover (or refund) some or all of that differential. In some regimes, the differential is measured prospectively (i.e., using forecasted fuel and purchased power prices) with a subsequent true-up to actual. Alternatively, the differential can be measured on a cost deferral basis, in which the deviation between base fuel costs and actual fuel costs for a given period are tracked and recovered in a subsequent period. Typical periods of measurement for this purpose can be monthly, quarterly, or annually.

Q. What general observations do you have regarding the adoption of an ECAM?

A. By its nature, an ECAM calls out specific expenses for recovery that are not included in rates when rates are set pursuant to a general rate proceeding. As such, it is a form of single-issue ratemaking, and should only be applied after carefully weighing the justification for such an approach against its several drawbacks.

Single-issue ratemaking occurs when utility rates are adjusted in response to a change in a single cost or revenue item considered in isolation. When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, the standard practice is to review and consider all relevant factors, rather than just a single factor. To consider some costs in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. Alternatively, a single revenue item considered in isolation might cause a decrease in rates without recognizing counterbalancing cost increases in other areas. For these reasons, single-issue ratemaking, absent a compelling public interest, is generally not sound regulatory practice.

ECAMs are the most commonly-adopted exception to the general strictures against single-issue ratemaking. ECAMs are typically justified on the grounds that they are necessary to ensure the financial well-being of the utility when it is subject to significant uncontrollable volatility in fuel and/or purchased power markets. An ancillary justification is that ECAMs can improve price signals by informing customers about changes in fuel costs and power prices in a more-timely manner than would otherwise occur in a traditional rate case.

Q. Why should the justification for an ECAM be tied to volatility in fuel and purchase power prices rather than longer-term changes in these prices over time?

A. Most of the pricing inputs into the ratemaking process change over time. The fact that prices change does not by itself justify single-issue ratemaking treatment. Changes in prices over time, including fuel and purchased power prices, are best addressed in a general rate case proceeding so that these prices can be considered in the context of all the relevant factors examined when setting rates. Single-issue ratemaking treatment should be reserved for situations in which the price of key inputs is highly volatile, such that the volatility places the utility at undue risk.

Q. Are there potential advantages for retail customers in the adoption of an ECAM?

A. Yes. One potential benefit of an ECAM is that it provides for savings to be passed through to customers if fuel costs decline below the level of base fuel costs. Absent an ECAM, this benefit would be retained by the utility. Another possible benefit, depending upon the specific design utilized, could be timelier price signals for customers.

In addition, in theory, the adoption of a fuel adjustor could reduce the number of general rate case filings. However, as I will discuss below, this potential advantage is not likely to be applicable to RMP in Utah for some time.

Q. Are there disadvantages for customers associated with an ECAM?

A. Yes. Among the more significant potential disadvantages are the following:

1. ECAMs typically result in more frequent rate changes, which can negatively impact rate stability.

2. Because ECAMs simply pass through changes in cost to customers, adoption of these mechanisms reduces a utility's incentive to manage its fuel and purchased power costs as well as it would manage them if the utility remained fully responsible for the energy cost risk.

3. ECAMs shift risks from utilities to customers. These risks include:

- Price risk
- Resource portfolio risk
- Weather-related risk
- Forced outage risk

4. It is can be difficult to measure the precise reduction in risk to the utility stemming from adoption of an ECAM or to identify a specific appropriate reduction in the utility's return on equity to account for the risk-reducing characteristics of an ECAM. Consequently, customers may not be adequately compensated for the risk-altering implications of an ECAM.

5. ECAM rate changes are typically reviewed in shorter time frames than general rate proceedings, providing reduced regulatory scrutiny.

6. While straightforward in concept, ECAMs can require complicated calculations, resulting in increased complexity in ratemaking. Moreover, attempts

to improve ECAMs by introducing certain features intended to protect customers (e.g., by removing forced outage risk) typically make the mechanism even more complicated. Thus, regulators considering the adoption of an ECAM must weigh the merits of incorporating improvements intended to protect customers from certain aspects of risk-shifting, with the increased complexity associated with any modifications to a basic plan. In addition, the existence of an ECAM must be taken into account in a general rate case proceeding, adding a different layer of complexity to the general rate case.

7. ECAMs reduce a utility's financial exposure to high marginal costs during peak pricing periods. This, in turn, reduces the benefit to the utility from demand-side management ("DSM") actions. Over time, this may encourage subsequent requests by the utility for expensive DSM incentive payments to overcome the "disincentive" to undertake DSM activities that is introduced when an ECAM is adopted.

8. Introduction of new wind facilities reduces average system fuel cost. If an ECAM is adopted, it may result in utility proposals for capital cost adjustments for new wind projects between rate cases. Indeed, RMP made just such a proposal in Wyoming after the introduction of Wyoming's version of an ECAM (although the proposal was later withdrawn).

9. Once ECAMs are introduced, utilities may attempt to expand the list of expenses eligible for inclusion, such as certain chemicals used in the operation of generation facilities.

Taken together, these disadvantages provide important reasons for a commission to proceed with great caution before adopting an ECAM.

Q. In light of the concerns you have identified, what factors should a regulatory commission consider before approving an ECAM?

A. A regulatory commission should consider, in sequence, three basic questions before adopting an ECAM:

1. Are the costs that would be recovered through an ECAM subject to significant volatility?
2. If yes, is the significant volatility in those costs largely beyond the control of management?
3. If yes, are the costs that could be recovered through an ECAM substantial enough to have a material impact on the utility's revenue requirement and financial health between rate cases if they were to go unrecovered?

In my opinion, an ECAM should not be considered unless the answer to each of these three questions is a clear "yes." Even then, the adoption of an ECAM should be carefully weighed against the disadvantages of single-issue ratemaking and the other disadvantages identified above. After weighing the disadvantages of adopting such a mechanism against these three factors, an ECAM may reasonably be adopted if a Commission finds that there is a compelling public interest in doing so.

Q. Have you considered RMP's proposal for an ECAM in light of these three criteria?

A. Yes, I have.

Q. Are the costs that RMP would recover through an ECAM subject to significant price volatility?

A. No, not as these costs are currently incurred by RMP. Volatile pricing implies frequent and sharp fluctuations in price. Such a description does not accurately characterize the fuel supply costs that would be recoverable through RMP's ECAM proposal.

According to the Company's most recent GRID filing in Utah, approximately 73 percent of RMP's generation output is coal-fired. RMP's coal supply is generally provided pursuant to long-term contracts and mines owned by corporate affiliates, the latter of which transfers coal to RMP's generation facilities at cost. Although the cost of RMP's coal supply may change from year to year, its price does not generally fluctuate significantly month-to-month. Therefore, the cost to RMP of its coal supply is not fairly characterized as volatile.

In addition, approximately 12 percent of RMP's generation output is renewable energy, consisting of hydro, wind, and geothermal. While the output of wind generation may be volatile, its cost of production is not. Nor is the cost of producing hydro and geothermal generation volatile.

RMP's remaining generation output is natural-gas-fired, which comprises about 15 percent of the Company's generation output. In general, it <u>is</u> fair to characterize the price of natural gas as volatile, as it is subject to significant swings. Consequently, I conclude that this portion of RMP's resource portfolio is subject to underlying price volatility. However, I would <u>not</u> characterize the effective cost to RMP of natural gas for power production as volatile given the manner in which the procurement of this fuel supply is managed by the Company. As I will discuss in my response to the second basic question, below, RMP's gas purchases are strongly hedged, effectively "managing away" the volatility of this component of its cost structure.

Q. What role is played by purchased power in meeting RMP's retail load requirements?

A. RMP engages in long-term purchases and sales, short term purchases and sales, and balancing purchases and sales. In long-term transactions, RMP is a net purchaser. By their nature, long-term purchases are not subject to price volatility.

In short-term and balancing markets, RMP is a net seller of power. As a net seller of market-priced power, increases in market power prices tend to *reduce* RMP's net power costs, all other things being equal, as margins from market power sales serve as a credit against the net power cost recoverable from retail customers. I believe it is fair to characterize underlying short-term and balancing markets as being subject to underlying price volatility. However, similar to RMP's procurement of its natural gas supply, RMP's market transactions are substantially hedged, significantly reducing the volatility of this component of its net power costs in practice.

In summary, although 15 percent of RMP's generation output, as well as its short-term and balancing market transactions, are subject to underlying price volatility, this volatility has largely been removed from RMP's net power cost by the Company's aggressive hedging practices, as will be discussed further below.

Q. Turning to the second question, are the components of RMP's fuel costs that are subject to underlying price volatility outside management's control?

A. The underlying prices of natural gas and short-term power transactions <u>are</u> outside RMP management's control, but the structure of the Company's procurement strategy is <u>within</u> management's control, including the development and implementation of its hedging program. Because of the Company's substantial hedging position, movements in natural gas and short-term power market prices do not translate into significant net power cost volatility. Thus, while the absolute level of the pricing is established externally to the Company, the relative lack of volatility of the prices once set is a function of management practice.

Q. Please elaborate on this point.

A. As has been discussed at some length in recent dockets, RMP's natural gas supply cost is very strongly hedged, with the Company entering forward commitments for the purchase of its forecasted physical requirements and financial swap contracts to manage price volatility. The Company's hedging strategy has placed a major emphasis on price stability over extended periods. As pointed out by DPU witness Douglas D. Wheelwright in Docket No. 09-035-23, according to the Company's 10-K reports, as of the end of 2008, RMP had hedged 64 percent of its forecasted physical gas exposure and 94 percent of its forecasted financial gas exposure for 2009. For 2010, the Company had hedged 48 percent of its forecasted physical exposure and 85 percent of its forecasted financial exposure. According to a report by DPU consultant Blue Ridge Consulting Services, RMP's hedging strategy "is more aggressive at locking in prices for longer periods of time" than most other utilities. [1] RMP also engages in substantial hedging for its short-term power market transactions.

Q. Can you cite any recent examples of how RMP's hedging practices have insulated the Company from price volatility?

A. Yes. In Docket No. 08-035-08, RMP filed projected net power costs using forward price curves dated November 4, 2008 for the test period ending December 31, 2009. Subsequent to the Company's filing, forward energy prices fell significantly. To better understand the impact of falling energy prices on RMP's net power costs, I requested that RMP provide an updated GRID run using the Company's most recent forward price curve dated December 31, 2008. In the updated GRID run, the market cost of fuel for RMP's gas generating units had fallen by approximately $77 million. However, despite this sizable reduction in fuel cost, projected net power costs fell by only $5.9 million in the updated GRID run, as the price of gas swaps increased by approximately $80 million. This

[1] Docket No. 09-035-23, DPU Exhibit 3.8, p. 4.

means the reduction in the market cost of fuel was offset by the increase in gas swap costs; in other words, RMP's hedging program had already locked in its forward fuel costs at the higher price level.

Q. How much movement has occurred in the Company's hedged cost of natural gas over the past several years?

A. There has not been a great deal of movement. Table KCH-1, below, tracks the per-MWh cost of RMP's gas-fired generation as filed by the Company in its past five general rate case filings in Utah. The table shows both the fully hedged cost as well as the market cost (hedged cost minus gas swaps and gas physical). Except for the discrete jump in cost between Docket Nos. 06-035-21 and 07-035-93, the hedged cost has remained relatively stable. I note that the discrete jump in cost was associated with a 44 percent increase in RMP's natural gas generation output, suggesting that structural changes to RMP's generation fleet may have also played a role in influencing the change in unit cost. I note also that I did not identify any hedging costs in the 04-035-42 docket.

Table KCH-1[2]

Unit Cost of RMP Gas-Fired Generation Output, Hedged and Market Cost

Docket	Test Period	Unit Cost ($/MWh)	
		Hedged Cost	Market Cost
09-035-23	Year ending June 2010	$52.58	$33.50
08-035-38	Year ending Dec 2009	$56.89	$48.45
07-035-93	Year ending Dec 2008	$52.33	$48.08
06-035-21	Year ending Sept 2007	$40.40	$59.44
04-035-42	Year ending March 2006	$39.88	$39.88

[2] Sources: Docket No. 09-035-23: RMP Exhibit GND-1; Docket No. 08-035-38: RMP Exhibit GND-1SS; Docket No. 07-035-93: RMP Exhibit GND-1S; Docket Nos. 06-035-31 & 04-035-42: RMP Response to DPU DR 4.14(g) in Docket 09-035-15.

Q. Please summarize your conclusions regarding the first two basic questions to consider when evaluating an ECAM proposal.

A. Based on the Company's fuel mix and hedging practices, I conclude that RMP's cost structure is not sufficiently volatile to justify adoption of an ECAM at this time.

Q. Based on this conclusion, is it necessary to address the third question in your list?

A. No. In my opinion, justification of an ECAM requires successive answers of "yes" to the three questions posed. However, it may still be useful to briefly address the remaining question for purposes of discussion.

Q. Turning to the third question, are the costs that could be recovered through an ECAM substantial enough to have a material impact on the utility's revenue requirement and financial health between rate cases if they were to go unrecovered?

A. This question presumes that a significant component of volatile costs has been identified. That is not the case here. However, if it were the case, a sensitivity analysis should be conducted to test the impact on the utility's return if these costs were to go unrecovered. A significant impact on return could cause one to reasonably conclude that an ECAM might be necessary to protect the financial wellbeing of the utility.

As RMP does not have a significant component of volatile costs, given its fuel mix and hedging strategy, this analysis is unnecessary at this time.

I note, however, that it would require a $91.7 million increase in net power cost (after rates are set) to reduce RMP's Utah return on equity by 100 basis points, all other things being equal.

Q. In your opinion, are there exceptions in which an ECAM can be justified when the answers to any of these three basic questions is "no"?

A. I believe an exception may be justifiable in situations in which a utility is subject to voluntary or statutory "stay-outs" from rate cases extending multiple years. In such situations, it may be reasonable to establish an ECAM to recover (or refund) changes in fuel and purchased power prices over time, i.e., from year to year, given the restrictions on the utility's ability to file a general rate case.

Q. Do you have reason to expect that RMP would operate under an extended "stay-out" regime if an ECAM were adopted?

A. I make no claim as to knowing how RMP's management would view such a prospect. However, such a regime does not appear consistent with RMP's pattern of filing frequent rate cases over the last number of years. Furthermore, the Company's announced plans for major transmission infrastructure investments suggest that extended stay-outs are unlikely. In addition, the advent of single-issue rate filings for capital additions in Utah suggests that rate filings of one kind or another will become even more frequent in Utah, not less. And, as single-issue cases can only be filed for major plant additions projected to be on line within eighteen months of a general rate case decision, RMP is incentivized to continue to file general rate cases regularly in order to keep this option activated.

Q. Given that you have concluded that because of RMP's hedging practices, the Company does not experience significant volatility in the price of its fuel, shouldn't an ECAM be a low-risk proposition for customers?

A. Not necessarily. Although RMP does not experience significant volatility in the price of its fuel, customers could still experience increased costs from adoption of an ECAM due to the shifting of weather-related risk, forced outage risk, and resource portfolio risk. Subsequent to the adoption of an ECAM, the Company could also change its hedging policy in a manner that would increase the pricing risk to customers. Finally, an ECAM could pass through cost changes that are not associated with price volatility, but which are still included in net power cost, such as an increase in BPA transmission charges. Such costs are more appropriately recovered pursuant to a general rate case rather than a single-issue proceeding.

Q. Please explain how an ECAM transfers resource portfolio risk to customers.

A. Utilities assume certain risks associated with the resource portfolios they have assembled. In the case of RMP, one example of this the risk is the potential for its hydro generation to be adversely affected by a poor water year. Currently, this risk is borne by the Company, at least as far as the Utah jurisdiction is concerned.

An ECAM, however, would transfer this risk to Utah customers. Base fuel prices are established in GRID assuming "normal" water conditions based on median hydro levels. A poor water year might require the Company to make more off-system purchases to replace reduced hydro production. This higher cost would be captured in the ECAM and passed through to customers. In this manner, the resource portfolio risk would be transferred to customers.

Q. Do you believe the transfer of hydro-related risk to Utah customers is appropriate?

A. No. Whereas the transfer of risk in general that accompanies an ECAM is a cause for concern (and a matter to be considered in determining return on equity), the transfer of hydro-related risk to Utah customers would be inappropriate because Utah does not receive a proportionate benefit from the PacifiCorp hydro resource. Although net power cost in GRID reflects the benefits of the hydro system, these benefits are largely "adjusted away" from Utah pursuant to the MSP Revised Protocol. Because Utah does not receive a proportionate benefit from the hydro system, an ECAM that subjected Utah to hydro-related risks would be unreasonable.

Q. You also stated above that ECAMs shift weather-related risk to customers. Please elaborate.

A. For Utah ratemaking purposes, RMP's net power cost is determined assuming a normal weather year. To the extent that deviations from normal weather result in an increased demand for power during peak periods, the risk of increased cost is absorbed by the utility. With an ECAM, any increased cost associated with deviations from normal weather would be passed on to customers (as would any reductions in cost associated with weather deviations).

Q. Please describe the shift in forced outage risk that occurs with an ECAM.

A. The loss of a power plant due to forced outage typically requires the procurement of more expensive replacement power. At the present time, the risk of greater incremental costs attributable to forced outages above baseline levels is absorbed by the Company, although for certain major outages the Company has sought and received deferred accounting treatment. Under an ECAM, incremental costs associated with forced outages would be passed through automatically to customers. At the same time, if forced outage costs turn out to be below the baseline level assumed in GRID, the reduction would also be passed through to customers.

Q. Can incremental forced outage costs be removed from an ECAM calculation?

A. Yes. I am aware of at least one jurisdiction, Kentucky, which removes incremental forced outage costs from its version of an ECAM. However, this provision adds a significant amount of complexity to its ECAM determination.

Q. Are there other factors that should be considered in the consideration of whether an ECAM is appropriate for RMP in Utah at this time?

A. Yes. The test period for ratemaking in Utah has changed from the regular use of an historical test period to the use of a fully projected test period in the last several cases. In jurisdictions using an historical test period, proponents of an ECAM may argue that an ECAM is necessary because the net power costs in rates are based on dated information. The use of a projected test period in Utah, however, eliminates this argument (although it introduces some prediction error). Taken in combination with RMP's aggressive hedging policy and its frequent rate case filings, the current use of a future test period in Utah further diminishes any justification for an ECAM in Utah at this time.

Q. Would your recommendation not to approve an ECAM for RMP in Utah change if the Company's hedging practices were modified?

A. Not necessarily. I am recommending that RMP's proposal for an ECAM be denied at this time given all the various factors that should be considered, including the effect of the Company's hedging policy on the volatility of its net power cost. Under current circumstances, an ECAM is not needed and is not in the public interest.

I recognize that RMP's hedging policy is under review in at least two dockets. What will result from those dockets remains to be seen. If the Company's hedging policy is altered, perhaps it will be changed to provide a greater potential for customers to benefit from reductions in fuel cost. However, other tradeoffs may be involved in the establishment of any new policy. The question of whether a new hedging policy would justify the adoption of an ECAM can only be reasonably considered once the parameters of any new policy are in place.

Q. Do you have any preliminary comments on Phase II issues at this time?

A. Yes. While ECAM design issues have been reserved for Phase II of this docket, I wish to stress the importance of designing any ECAM such that risks and benefits are shared between customers and the utility. If an ECAM is adopted, this would mean eschewing a design in which 100 percent of deviations from net power costs in base rates are allocated to customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.