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

Q. Please state your name, current professional position and business address for the record.

A. My name is Karl A. McDermott. I am currently the Ameren Distinguished Professor of Business and Government at the University of Illinois at Springfield and a Special Consultant to National Economic Research Associates, Inc. ("NERA"). My business address is 875 North Michigan Avenue, Suite 3650, Chicago, Illinois, 60611.

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

A. I have been asked by Rocky Mountain Power[1] to provide responses to issues raised by the Utah Public Service Commission's June 18, 2009, Procedural Order and by other parties in their comments in this docket. In general these issues address the public interest aspects of adopting an adjustment clause, i.e., the Energy Cost Adjustment Mechanism ("ECAM") that is designed to recover, through adjustable rates, certain O&M costs, namely fuel and net purchased power and related expenses, referred to as Net Power Costs ("NPC"), between rate cases.[2] My review is limited to the justification of such ratemaking mechanisms both generically, as a well-used method employed by regulatory bodies to address similar costs, and specifically as it applies to Rocky Mountain

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

[2] The ECAM is Rocky Mountain Power's specific ratemaking proposal. These ratemaking mechanisms may be referred to as fuel clauses or fuel adjustment clauses ("FACs"). In this testimony, I will generally refer to this type of ratemaking mechanism as an ECAM.

Power's proposal. I will also address certain questions raised by comments on this proposal by parties to this case.

Q. Would you please summarize your conclusions?

A. The ECAM mechanism proposed by Rocky Mountain Power conforms to good regulatory practice and should be approved by the Utah Public Service Commission ("UPSC" or "Commission"). Specifically,

- *Traditional regulation cannot always address every cost factor equitably and needs to be modified to maintain the balance between customers and the utility's shareholders.* Cost factors that violate the stability assumptions embedded in traditional rate case regulation of utility prices, such as NPC, are more equitably and efficiency recovered through a tracking mechanism, such as the ECAM.
- *ECAMs are important to allow management to focus on costs it can control.* Providing recovery of NPC through an ECAM provides the utility with the incentive to focus on costs it can control while potentially reducing the need for future rate increases.
- *NPC are large, volatile, and largely outside the control of the utility suggesting that an ECAM is the appropriate method for cost recovery.* Large and volatile costs that are beyond the control of the utility generally violate the assumptions of the traditional rate case method for setting rates and should be recovered through an ECAM. This benefits the utility and consumers, and provides for a more focused review of utility practices.
- *Regulatory bodies in the United States have uniformly adopted ECAMs.* It is

beyond question that ECAMs are the dominant method used by state regulators to recover NPC that are large, volatile, and largely beyond the utility's control.

- *Arguments that ECAMs will increase rates must presume that current rates do not recover NPC*. ECAMs are consistent with the regulatory bargain that utilities are provided with a reasonable opportunity to recover prudent costs and ratepayers pay no more than required to recover those costs. Since an ECAM will only recover actual, prudent NPC, concern that adoption of an ECAM will result in a rate increase must be based on the premise that existing rates do not appropriately cover prudent NPC. This premise is not in the interests of the utility's shareholders or ratepayers because it will either impair the financial viability of the utility or it will force utility management to cut prudent operating costs or to curtail needed investment.

II. WITNESS QUALIFICATIONS

Q. Please state your qualifications for presenting testimony before the Utah Public Service Commission in this docket?

A. I have been working in the field of public utility regulation for over thirty years with experience in nearly every facet of the regulation of public utilities. I am currently the Ameren Distinguished Professor of Government and Business at the University of Illinois at Springfield ("UIS"), a position I have held since April 2008. At UIS, I teach classes on the regulation of business in the US economy and I am also the Acting Director of the Center for Business and Regulation ("CBR") housed in the College of Business and Management at UIS. At CBR, I direct programs on education and outreach for the regulatory and university community as well as perform research on issues pertaining to the regulation of public utilities.

From 1999 through March 2008, I was a Vice President at National Economic Research Associates, Inc. ("NERA"). My practice focused on public policy and analytical issues facing public utilities and regulatory bodies in the U.S. and abroad. I continue to have an affiliation with NERA as a Special Consultant.

Prior to joining NERA, I served as a Commissioner on the Illinois Commerce Commission ("ICC"). The ICC regulates Illinois electric utilities, among other competencies.

Prior to joining the ICC, I co-founded and served as the President of the Center for Regulatory Studies ("CRS"), a not-for-profit regulatory policy institute located on the campus of Illinois State University. At CRS I was directly or indirectly involved in addressing a wide range of regulatory policy issues facing state policymakers including the ICC and the state legislature. Before co-founding the CRS, I worked in numerous capacities as a regulatory analyst including positions on the staff of the ICC, the National Regulatory Research Institute at The Ohio State University, and Argonne National Laboratory.

In addition, I have also taught graduate and undergraduate level economics courses, including regulatory economics, at Illinois State University and undergraduate economics courses at The Ohio State University, and the University of Illinois at Urbana-Champaign. I am currently on the faculty of the Institute for Public Utilities at Michigan State University where I am an invited lecturer at several of the Institute's regulatory studies programs, including its Annual Regulatory Studies Program (i.e., "Camp NARUC").

I have testified before many state regulatory bodies, as well as before the Federal Energy Regulatory Commission, the Federal Communications Commission, and the Iowa and Illinois General Assemblies on issues concerning public utility regulation.

I received a B.A. in Economics from Indiana University of Pennsylvania, an M.A. in Public Utility Economics from the University of Wyoming, and a Ph.D. in Economics from the University of Illinois at Urbana-Champaign. A more detailed description of my background can be found in my curriculum vita attached to this testimony as Exhibit RMP___(KAM-1S).

Q. Have you previously testified before the Utah Public Service Commission?

A. Yes. I testified regarding marginal cost pricing in Docket No. 07-035-93.

III. THE NEED FOR ECAM RATEMAKING

Q. Would you please describe the process of traditional ratemaking?

A. Traditional ratemaking uses an administrative process to identify the legitimate costs of serving customers and set prices for service through a traditional rate case system which allows rates to change only as a result of a regulator approving the prices in a general rate case. At the conclusion of the rate case the utility's rates, as approved by the regulator, are considered just and reasonable on a going-forward basis. That is, the regulator has determined the rate levels are sufficient to allow the utility to attract the necessary capital to finance its operations in order to provide the services consumers demand while at the same time charging consumers a fair price for the services purchased. This is the essence of what some have called the **regulatory bargain.** This bargain is two-sided—utilities are provided a reasonable opportunity to recover operations and capital costs and ratepayers pay no more than required to recover those costs. This traditional regulatory bargain equates just and reasonable rates with cost-based rates.

Q. Has this process stayed static over time?

A. No. Much of the history of ratemaking tells a story of grappling with the different dimensions of discovering just and reasonable costs and prices. The dimensions of this problem have ranged from reviewing the prudence of management decisions to assure that rates reflect costs associated with reasonable management practices to the effects of various market, technological, and social issues that bear upon the services the utility provides. Regulators have added procedures, e.g., management audits, prudence reviews, and cost recovery mechanisms such as ECAMs, riders, and trackers to the basic approach in order to be assured that customers get a fair deal and the utility can maintain the needed investment in the system.

Q. Would you please describe the changes that regulators have implemented over time to address the changing economic environment?

A. From its inception regulation has searched for and often found methods of accurately tracking costs while preserving the incentive to control costs. Whether it was the adoption of so-called sliding scale mechanisms in Sheffield, England in 1855 or the experiments in Boston, Detroit, Washington D.C., Houston, and Memphis in the first half of the twentieth century to more modern modifications such as trackers, balancing accounts, riders, and price caps, regulators have attempted to track input cost changes for decades and have found equitable methods of doing so.[3]

The weight of history indicates that serving the public interest has employed numerous mechanisms to preserve the cost basis of rates while maintaining the incentive to control costs. In addition to ECAMs, regulators have used many different tools to maintain the regulatory bargain:

- *Interim rates:* This method allows rates to go into effect at the time of filing with refunds or surcharges made after a complete review of the rates is complete. This mechanism focuses on maintaining financial stability for the utility during the period of rate review.[4]
- *Trackers:* Trackers have been employed for recovering specific expenses such as bad debt,[5] pension costs,[6] environmental costs,[7] storm damage costs,[8] and certain capital items such as smart grid or advanced metering investments.[9]
- *Formula Rates:* These mechanisms allow rates to change based on the changes in accounting costs or other pre-determined cost factors. [10]

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[3] *See e.g.,* M. Schmidt, (1980). *Automatic Adjustment Clauses: Theory and Application*, MSU Press, East Lansing, MI. for a summary of a number of mechanisms. *Also see* P. Joskow and R. Schmalensee,(1986). "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation*. 4(1), 1-50.

[4] Standards for interim rates in Utah are discussed in Utah Public Service Commission, Order in Docket No. 90-049-06 (June 22, 1990) and Order in Docket No. 99-057-20 (January 25, 2000).

[5] *See e.g.*, Vectren Energy Delivery of Ohio, Inc. Tariff for Gas Service, P.U.C.O. No. 2.

[6] *See e.g.*, NSTAR Electric-Boston Edison Company, Rate PAM-1, M.D.T.E. No. 109, effective January 1, 2004.

[7] *See e.g.*, Commonwealth Edison Company, Rider ECR, Ill. C.C. No. 10, Original Sheet No. 240, effective January 15, 2009.

[8] *See e.g.,* Florida Public Service Commission, Order No. PSC-05-0748-FOF-EI (approving a storm cost recovery mechanism for Progress Energy Florida).

[9] *See e,g,*, Portland General Electric Schedule 111, Original Sheet No. 111-1, effective June 1, 2008; California Public Utilities Commission, Decision 08-09-039, September 18, 2008 (approving Southern California Edison's AMI Cost Recovery Mechanism).

- *Decoupling:* More recently in an effort to address issues related to cost recovery in a world of declining per capita usage and increased emphasis on energy efficiency some states have moved to break the link between sales and revenue.[11]
- *Future test years:* Projection of costs in the period that rates are to be in effect that is designed to minimize the regulatory lag and the concomitant inability of the utility to have a reasonable opportunity to earn its allowed return as a result of stale historic accounting data that would otherwise be used to set rates.
- *Rate phase-in plans for major capital investments.* Many utilities that are embarking on major construction projects are working with their regulators to find appropriate rate mechanisms. Some states are pursuing policies aimed at providing incentives to build new generation. A number of traditionally regulated states have recently passed laws providing for prior review of plant and the inclusion of construction work in progress ("CWIP") in rate base.[12]

Q. Do any of these mechanisms address the volatility and uncertainty of NPC?

A. No. Each of these mechanisms is designed to address particular problems that arose in the context of the traditional ratemaking paradigm. In that sense, ECAMs

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[10] *See e.g.*, Alabama Public Service Commission, *Alabama Power Company Petition to amend Rate CNP Docket Nos. 18117 and 18416*, April 10, 2000; Mississippi Public Service Commission, "Notice of Intent of Mississippi Power to Reclassify Generating Facilities and to Modify Certain Provisions of its Performance Evaluation Plan," Docket No. 2003-UN-0898, May 25, 2004.

[11] A survey of electric and gas decoupling can be found in: P.G. Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review," Regulatory Assistance Project, June 2009.

[12] *See e.g.*, Public Service Commission of Wisconsin, Order in Docket 05-AE-109, December 20, 2002 (approving a contract for pre-approved generation costs). *Also see* "Construction Work in Progress," Regulatory Research Associates, April 7, 2009.

are similar to these other mechanisms, but ECAMs do not necessarily substitute for any of these other mechanisms. For example, while future test years are designed to better match future prices with future costs the fact that a future test year uses a forecast of energy costs to set prices does not address the fundamental issue that NPC are volatile and unpredictable. Interim rates tend to be used in emergency situations not with on-going costs. Trackers are similar to ECAMs, but generally address other costs deemed to be out of the control of the utility (e.g., environmental costs or pension expenses). Most of the other mechanisms address capital costs. ECAMs, therefore, are part of the adjustments that regulators have made to traditional regulation to address unique circumstances.

Q. What aspects of the traditional regulatory process can become problematic?

A. Like any process, especially one designed to operate over time, the regulatory process employs implicit and explicit assumptions. For example, costs, whether historic or forecasted, are assumed to represent the normal or expected costs of operating the utility. Once the normal level of costs are indentified and rates are established management is assumed to operate the utility efficiently such that the random effects of inflation, productivity changes, demand fluctuations, will, on average, tend to cancel out. As a result, a rate review becomes necessary only when cost increases have eroded the utility's ability to earn a sufficient return to attract the capital necessary to manage the company consistent with the public interest. We assume that **regulatory lag**, the time between the change in costs and the date that new rates go into effect, will not materially affect the utility's ability to recover its prudently incurred costs. Unfortunately, history is replete with examples of how reality does not always comport with these assumptions.

Q. Would you please describe the types of events that can cause stress on the system?

A. Rapid price inflation was perhaps the first serious factor that began to erode the ability of traditional regulation to set fair prices. If prices for certain inputs are rising faster than the utility's ability to receive a rate increase then its ability to recover its prudently incurred costs will be limited. This is especially acute for utilities as each has an obligation to serve all customers willing to pay the posted tariff rate. Price inflation can be even more problematic when it affects inputs that management has little or no control over.

A second problem occurs when the costs subject to inflation are a significant portion of the utility's cost structure. What makes the cost of paper clips different from the cost of generation inputs (e.g., coal, gas, or purchased power) is that the former has little impact on the utility's budgets and earnings while the latter tends to make up a significant percent of operating costs.

Third, volatility of the prices makes procurement of generation inputs much more problematic for utilities in terms of cost recovery and planning for meeting load.

Q. What are the implications of these problems?

A. When these three characteristics (large, volatile, and uncontrollable costs) exist they endanger the inherent fairness of the regulatory process and place the public interest in jeopardy. The regulatory process has, in effect, established a budget constraint for the utility management to operate under. Given the assumption of normal fluctuations and normal prudent management, we expect a utility could reasonably operate within this constraint. Once we admit that a large and volatile cost fluctuation can occur with little or no managerial control then the regulatory imposed budget constraint no longer represents a reasonable constraint and the utility is forced into decisions that could have negative impacts on customers. Because the utility has an obligation to serve it must incur prudent costs to serve customers even if it has no method to recover those costs. As a result, tradeoffs are imposed on management that may require budget cuts to capital expenditures, O&M, and other cost components under management's control that may have long term impacts on customers. Requiring the utility to bear the burden of these adjustments forces the utility to accept a lower return than is reasonable.

Q. Is an ECAM-type mechanism part of the solution to this problem with the traditional cost of service paradigm?

A. Yes, I believe so. A more eloquent summary of the fundamental public interest reason for a ECAM-type mechanism is provided by the Federal Power Commission (the predecessor of the Federal Energy Regulatory Commission):

> We recognize the need for a fuel adjustment clause. Properly administered fuel clauses can accomplish legitimate public interest objectives. Fuel clauses serve as a cost of service type mechanism to pass through changes in actual, reasonably and prudently incurred costs of fuel (decreases as well as increases), ensure appropriate and timely cash flow to electric utilities by eliminating "regulatory lag", and reduce regulatory expense, administrative process costs and the number of formal rate proceedings. These features of the fuel clause inure to the benefit not only of the public utility but also the customers and taxpaying public. However, improperly administered or inadequately regulated by governmental authority, fuel clauses can be inequitable and unfair.[13]

[13] 40 Fed Reg. 26702, 26705 (1975).

Q. Do you agree with the Federal Power Commission that ECAMs can be designed to be inequitable and unfair?

A. Yes. It should be clear that just because a mechanism has the name "ECAM" does not guarantee its equitable application. For example, there are examples of ECAMs that require the utility's shareholders to pay part of the prudent and reasonable costs incurred on behalf of consumers. This design constitutes an inequitable ECAM. Customers could also be treated unfairly, if, for example, the utility was not held to the proper standard of care (i.e., prudent behavior). The purpose of this testimony is to show that implementing a fuel clause is a reasonable and necessary regulatory response to the issues raised above. I believe the evidence also shows that the proposed ECAM is a fair and equitable mechanism that accommodates appropriate oversight by the Commission.

Q. In the absence of an ECAM, does a utility have a "reasonable opportunity" to recover prudently incurred costs?

A. It depends. If cost variations over time are manageable, as the traditional rate case model assumes, utilities that are operated in reasonable manner will, on average, have the opportunity to recover allowed costs. If it can be shown, however, that the rate case model assumptions are violated it is likely, and in many instances nearly assured, that the utility will not have a reasonable opportunity to recover its costs and regulators would need to look to alternatives to traditional regulation or an additional mechanism to augment traditional regulation to maintain the balance of the regulatory bargain.

Q. What are the implications for a utility's financial health from the inability to recover its costs?

A. Volatile costs components, such as NPC, have the ability to wipe out a substantial portion of utilities' earnings at any given time. Clearly this will affect the assessment of the utility's financial risk. For example, in 1998, S&P noted that "pass-through mechanisms that hold companies harmless from uncontrollable costs, such as fuel or foreign exchange effects, are viewed favorably."[14] Similarly, Fitch has noted

> Although a majority of integrated utilities remain substantially protected from fluctuating commodity price levels due to the existence of fuel/purchased power adjustment clauses…a handful of companies possesses regulatory mechanisms that offer only partial protection while others lack such a clause altogether…. Unless a protective adjustment mechanism is in place, utilities purchasing power from the spot market to meet load requirements will be particularly exposed to high costs during periods of high demand, when gas is likely to be on the margin in all U.S. regions.[15]

For Rocky Mountain Power, the lack of an ECAM has caught the attention of the financial community. In 2008, Standard and Poor's cited the absence of an ECAM in Utah (as well as Washington and Idaho) as contributing to "below-average regulatory protection from fuel and purchase power escalation."[16]

Regulators have not been blind to the concerns raised by Wall Street. For example, recently the Missouri commission stated, "[t]hat the mainstream of regulation recognizes a utility must be able to recover its prudently incurred fuel costs and that it is impossible for a utility to earn its allowed return on equity in a

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[14] *Standard & Poor's,* "Rating Methodology For Global Power Utilities," *Standard & Poor's Infrastructure Finance*, September 1998, p. 66.

[15] F*itch*, "Natural Gas Price Sensitivity of the U.S. Utility Sector," July 1, 2004, p. 4.

[16] Standard and Poor's, Research Summary on PacifiCorp, April 22, 2008.

rising cost environment without a fuel adjustment clause."[17] The Colorado PUC recognized that unless increased fuel costs were passed through to customers expeditiously, the utility would undergo a serious erosion of earnings jeopardizing the utility's ability to provide service.[18] Finally, the California Public Utilities Commission includes financial stability among its goals for employing interim recovery mechanisms for generation costs:

> …the objectives in developing an interim cost recovery procurement mechanism are to:
>
> - improve the ability of the respondent utilities to meet their obligation to serve their customers' electric loads;
> - assure just and reasonable electricity rates;
> - enhance the financial stability and creditworthiness of respondent utilities;
> - diminish the need for after-the-fact reasonableness reviews of procurement purchases;
> - ensure the timely recovery in rates of procurement costs in order to support the credit of the utilities that function as load serving entities;…[19]

Q. You seem to be focusing on a utility's recovery of its costs. Why should consumers be supportive of this proposal?

A. Beyond the principle that both sides of the bargain—utility customers and shareholders—should be treated fairly, and nothing in that bargain excuses customers from paying for prudently incurred costs, we should expect that consumers will be better off under an ECAM approach than the current method of

[17] Missouri Public Service Commission, Report and Order in Case No. ER-2008-0318, January 27, 2009, p. 32.

[18] Before the Public Utilities Commission of the State of Colorado, "In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities," Docket No. 93I-702E, Decision No. C95-248, February 6, 1995.

[19] California Public Utilities Commission, Decision 02-10-062, October 24, 2002.

recovering net power costs. There are two basic reasons for this expectation. First, consumers are not simply “ratepayers.” Consumers are individuals, firms, and other organizations that depend on electric service to power their homes, businesses, and operations. Consumers benefit from electric service provided in an efficient and timely manner. Providing utilities with a reasonable opportunity to recover prudently incurred costs helps create an environment in which capital can be obtained on more favorable terms in order to provide safe, reliable, and reasonably priced electric services on an **on-going** basis. While maintaining the *status quo* may, in the short-term, cause prices to be lower, in the long-run the negative results of higher capital costs, excessive cost cutting of manageable costs, and perhaps even underinvestment in facilities and maintenance will present risks to consumers that are likely to far outweigh the short term gain, if any. One need only consider the enormous costs of outages or slower restoration times to understand that refusing to allow reasonable cost recovery shifts colossal risk onto the backs of consumers. (Also note that due to the nature of Rocky Mountain Power’s particular proposal, prices increase only when actual costs are higher than the assumed level embedded in rates; when actual costs fall, the ECAM rate will fall in tandem.)

Second, consumers, and indeed, society, benefit when the price of electricity reflects the cost of production. This promotes the right amount of consumption on the part of consumers and provides benefits by directing consumers to consume only that incremental amount of electricity that provides them an equal incremental benefit. While this benefit may seem ethereal, it is none-the-less quite tangible and regulators have identified this as a benefit of ECAMs. For example, the Minnesota Public Utilities Commission notes that ECAMs are

> …intended to make rates more accurate and reasonable…[S]ince fuel and purchased power costs can fluctuate significantly between rate cases, building these costs into non-adjustable rates can cause significant, reoccurring mismatches between expenses and rates.[20]

Furthermore, better pricing in the natural gas industry has helped guide consumers to significantly reduce per-capita consumption; oil markets have shown a similar response as cars and factories have become more energy efficient. Figure 1 illustrates these effects. Note especially the increase in energy efficiency for petroleum products after the oil price shocks in the mid 1970s. A similar effect occurred in the natural gas market after the 1990s as prices changed to reflect new supply and demand conditions (although the trend was apparent prior to this time).

[20] Minnesota Public Utilities Commission, Docket Nos. E-002/M-02-2097 and E-999/CI-03-802, June 4, 2003, p. 2.

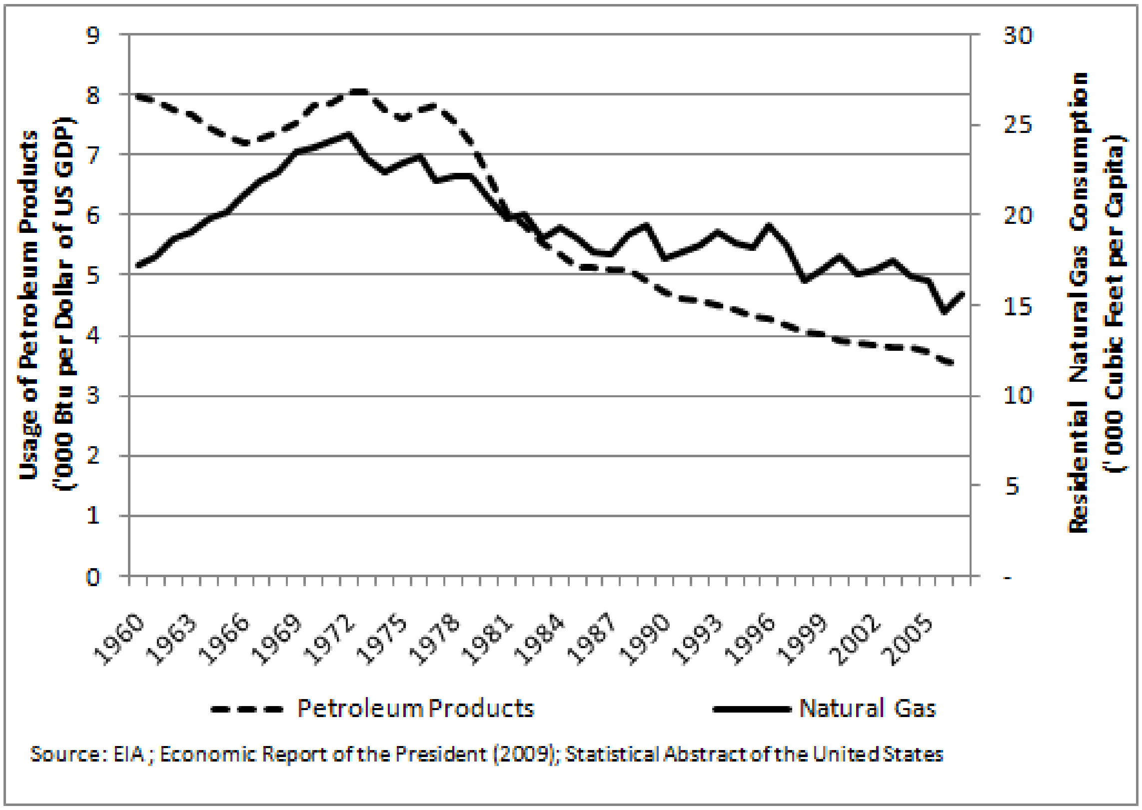

Figure 1: US Natural Gas and Petroleum Usage (1960-2007)

Q. You have used the term "opportunity" when referring to the potential cost recovery under the proposed ECAM; yet the ECAM guarantees cost recovery for costs that would otherwise not have been recovered under the current rate case approach, does it not?

A. No. Under the current rate case approach costs that are prudently incurred and reasonable are allowed to be recovered in rates. The standard for cost recovery does not change under the ECAM proposal. Rocky Mountain Power will still be required to justify every dollar that passes through the ECAM just as it does in its rate cases. The only difference between the two mechanisms is that the ECAM provides an opportunity to recover those prudently incurred costs whereas the rate case approach does not, but the ECAM does not guarantee recovery of *any* costs.

Additionally, a general rate case, whether using a historical test period or a forecast test period, is trying to predict the future level of a volatile cost component of rates. Since there is no balancing account for this specific cost component, the Company will likely either over or under collect NPC.

One might be tempted to argue that the difference between the forecasted level of costs embedded in a rate case and the actual level would never be recovered by the utility under a rate case approach due to the lack of a balancing account and the prohibition on retroactive ratemaking suggesting the ECAM will always cause higher prices. If this were true, however, the forecast level of net power costs allowed in base rates must be biased downward and therefore the rates set in the rate case are unjust and unreasonable. If the forecasted level of net power costs could be set such that, on average, the utility would be expected to recover its costs from the rate case approach, a fundamental premise of ratemaking, then the rate case approach and the ECAM approach will produce, on average, the same rates. The question for this case revolves around the reasonableness of relying on a forecast approach (i.e., a rate case whether with a future or historical test year) as opposed to the actual costs (i.e., an ECAM), not whether customers will pay higher or lower rates.

IV. THE CHARACTERISTICS OF NET POWER COSTS JUSTIFY AN ECAM APPROACH

Q. What are the typical justifications for ECAM ratemaking mechanisms?

A. The three typical justifications are:

- The item constituted a significant or large component of the utility's total operating cost;

- The cost changes with respect to that item were volatile and unpredictable;
- The cost of the item is largely outside of the control of the buying utility. [21]

Q. Are these justifications still relevant for the Utah PSC?

A. Yes. These three justifications have been used in many jurisdictions that have approved ECAMs. For example, earlier this year the Missouri Public Service Commission reviewed an ECAM proposal by Union Electric and cited these three factors as the justification for tracking fuel and purchased power costs.[22] Courts have used similar tests for reviewing rider mechanisms. For example, the Illinois Appellate Court has noted that a rider mechanism is an effective and appropriate cost recovery mechanism when utilities are faced with unexpected, volatile, or fluctuating expenses that are beyond the control of the utility.[23] In fact, this court specifically identified fuel costs as a prime example of the types of costs that meet this standard.[24] Finally, in describing the ECAM process to consumers, the Kentucky Public Service Commission's literature makes the following statement:

> Fuel costs make up a significant portion of the cost of generating electricity. Fuel prices, including the price of coal (used to generate 95 percent of Kentucky's electricity) can fluctuate widely over relatively short periods, as can the price of purchased power. The [ECAM] allows utilities to reflect those fluctuations in their electric rates without having to request changes in their base rates. Without the [ECAM], utilities would likely be required to file for more frequent adjustments in their base rates, and the changes in base rates would be greater.[25]

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[21] R. Burns, M. Eifert, and P. Nagler, (1991), "Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets," National Regulatory Research Institute. Also the Utah Division of Public Utilities ("DPU") cites these three criteria in its comments to Rocky Mountain Power's proposal. The DPU also adds a fourth dimension related to the timing of the volatility of costs. This issue is addressed within the discussion of NPC below.

[22] Missouri Public Service Commission, *supra* note 17, p. 34.

[23] *A. Finkl & Sons v. Ill. Comm. Comm'n*, 250 Ill. App. 3d 317 at 325 (1993).

[24] *Id.*

[25] "The Fuel Adjustment Clause: Frequently Asked Questions," Kentucky Public Service Commission, (http://psc.ky.gov/agencies/psc/consumer/FAC%20Q&A.pdf, accessed August 1, 2009)

Q. Which costs does Rocky Mountain Power propose for the ECAM to cover?

A. I understand that Rocky Mountain Power proposes to track the following FERC account cost categories for potential recovery through the ECAM (the total of these accounts is referred to as Net Power Costs or NPC):

Account 447 - Sales for Resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID

Account 501 - Fuel Expense, steam generation; excluding fuel handling, start up fuel/gas[26], diesel fuel, residual disposal and other costs that are not modeled in GRID

Account 503 - Steam from Other Sources

Account 547 - Fuel Expense, other generation

Account 555 - Purchased Power, excluding BPA residential exchange credit pass-through

Account 565 - Wheeling Expense

Q. Are these costs typically recovered through ECAMs?

A. Yes. Exhibit RMP___(KAM-2S) provides a survey of the types of costs that are allowed to be recovered through ECAMs in the US. Most states allow both fuel expenses and purchased power costs, or at least the energy portion of those costs, which represent a significant portion of the net power costs for Rocky Mountain Power. (Not all states net power sales revenue through the ECAM, in those cases a normalizing adjustment is generally made in the revenue requirement.)

Q. Are the NPC typically a large fraction of a utility's operations cost?

A. In my opinion these costs do represent a large fraction of a utility's operations costs. For example, the fraction of fuel and purchased power to total operations

[26] Start up fuel is accounted for separate from the primary fuel for steam power generation plants. Start up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of net power costs.

cost for US electric utilities have ranged from 39.2 to 59.8 percent for the years 1992 through 2007. (See Figure 2) While there is no universally-accepted definition for a "large fraction," NRRI concludes that "…fuel and purchased gas costs…constitute a significant proportion of a utility's operating costs…most other variable costs do not represent a significant proportion of a utility's operating costs…"[27] The data support this conclusion.

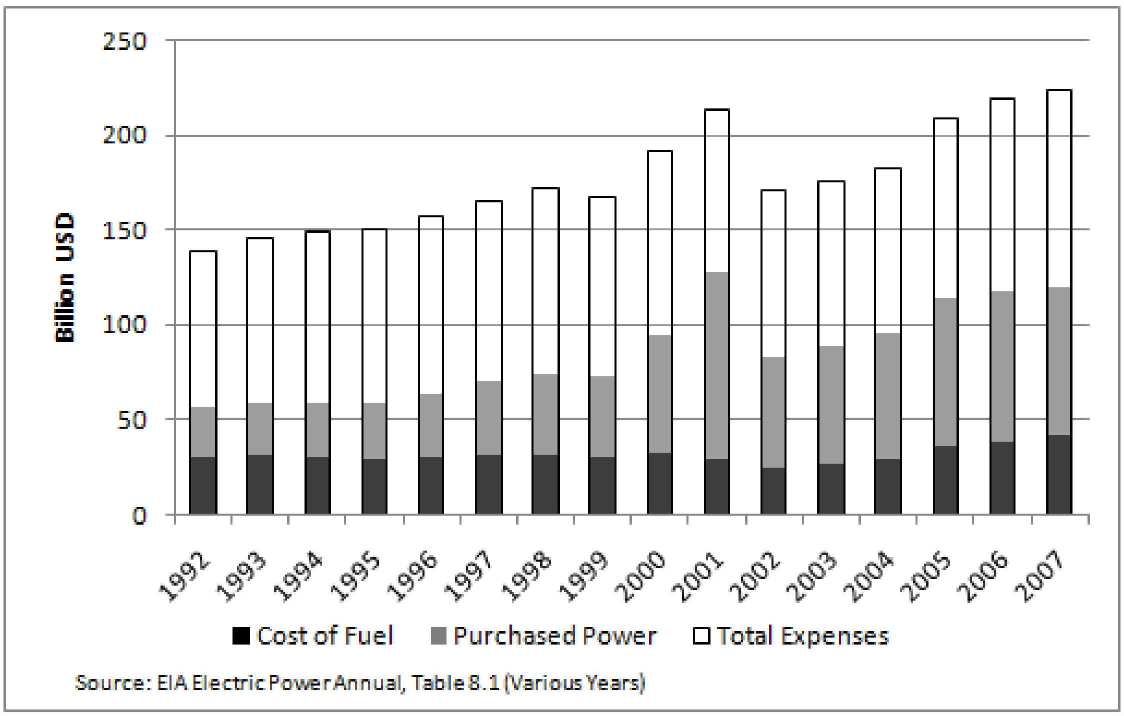

Figure 2: Fuel, Purchased Power, and Total Expenses for US Investor-Owned Electric Utilities (1992-2007)

Q. Does this same relationship hold true for Rocky Mountain Power?

A. Yes. For example, from 1992 to 2008 PacifiCorp's fuel and purchased power costs ranged from 42.4 to 79.1 percent of total expenses. (*See* Figure 3) (NPC, which offsets fuel and purchased power costs with revenues from off-system sales, ranges from 11.3 percent to 37.4 percent of total expenses.) In my opinion

[27] NRRI, *supra* note 21

there is no question that NPC represent a significant cost to electric utilities, in general, and Rocky Mountain Power in particular.

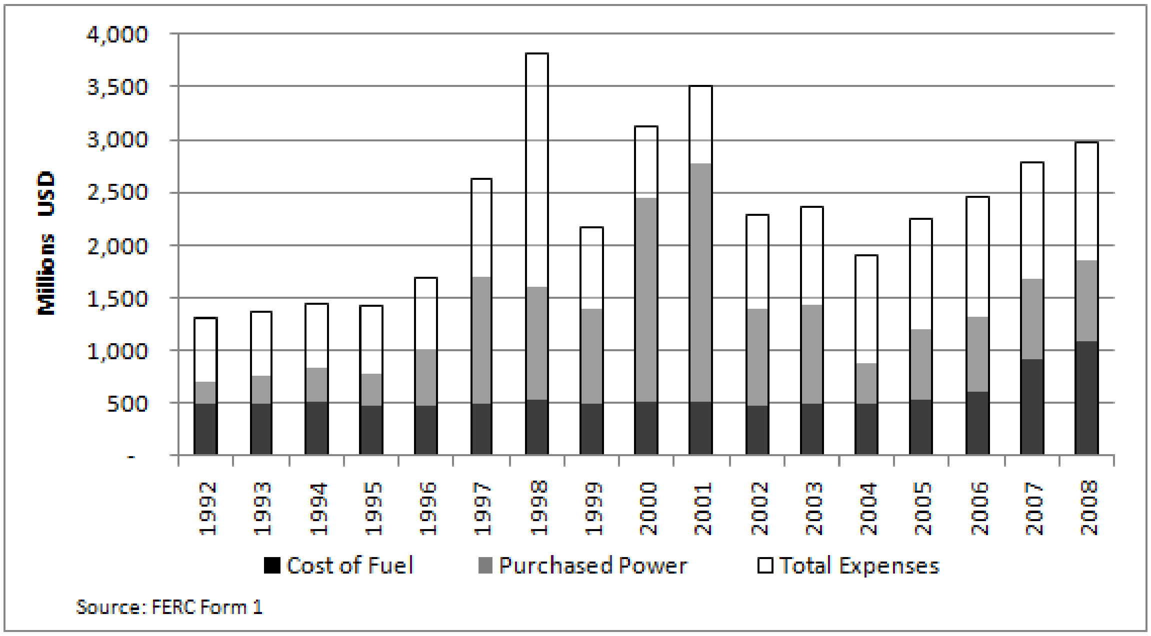

Figure 3: Fuel, Purchased Power, and Total Expenses for PacifiCorp (1992-2008)

Q. Is this the only metric you have relied on to conclude that these costs represent a significant expense for utilities?

A. No. Another relevant analysis reviews NPC as it relates to net income. From the same data that underlies Figure 2 an evaluation of volatility of these expenses is reported in Table 1. The mean value of all expenses, other than fuel and purchased power, is approximately $92 billion annually for the industry. Non-power expenses, however, do not vary much from year to year (standard deviation = $6 billion). This implies that utilities can be relatively confident that net operating income will not vary year to year much as a result of the volatility of non-fuel operating costs. The story is quite different when we look at purchased power and cost of fuel. While the mean values for the fuel and purchased power combined roughly equal all other expenses, the standard deviation is four times that of non-fuel expenses. As the mean net operating income for this time period equals roughly $30 billion annually, one can conclude that the variations from year to year in fuel and purchased power costs represent a significant proportion of the utility's net operating income (compare the standard deviation of fuel and purchased power to the mean net income). This further supports a conclusion that net power costs represent a significant, volatile expense for electric utilities.

Table 1: Summary Statistics for Fuel and Purchased Power Costs for the US Electric Industry (1992-2007)

Cost Category	(A) Mean (Billions USD)	(B) Standard Deviation	(C) = (B) / (A) Coefficient of Variation[28]
Total Expenses	177	27	0.15
Cost of Fuel	31	4	0.14
Purchased Power	53	23	0.42
Fuel + Purchased Power	85	25	**0.29**
All Expenses less Cost of Fuel and Purchased Power	92	6	**0.06**

Source: Data used to compile Figure 2

Q. Turning to the second justification noted above, are NPC volatile and unpredictable?

A. From the evidence presented in this docket I can confidently conclude that NPC are volatile and unpredictable.[29] There are several reasons for this observation.

First, fuel markets are commodity markets and as such tend to be volatile. Natural gas markets have well known volatility as a result of both supply and demand

[28] The coefficient of variation measures unit variation of data set, measured by the standard deviation in terms of the mean or average. This is a useful tool to compare data sets with different means; the larger the coefficient of variation the more variation per unit of mean.

[29] Supplemental Direct Testimony of Gregory N. Duvall and Supplemental Direct Testimony of Frank C. Graves filed on behalf of Rocky Mountain Power in Docket No. 09-035-15.

conditions as well as seasonal and regional factors.[30] On the supply side, disruptions in distribution channels and production can be caused by unpredictable weather affecting the production regions such as the Gulf Coast. Hurricanes and other weather phenomena are a constant threat to this area, yet we generally cannot predict exactly when such events will occur in order to take this into account, through gas price forecasts, in a general rate case.[31] Natural gas demand is influenced by colder than normal weather conditions that can cause demand to increase and lead to unpredictable increases in price due to unpredictable changes in weather. All of these factors suggest that the commodity price of natural gas will be quite volatile and indeed this is the case.

Hydrological conditions can have a large influence on power markets in the northwest and western areas of the United States.[32] Light snow years can cause lower levels of run-off and lower levels of power production. Again, while we know these conditions will occur from time to time, we cannot predict such events with enough accuracy to include in a rate proceeding.

Even coal prices can be volatile. (See Figure 4) Although volatility of coal markets is mitigated for Rocky Mountain Power as a result of its ownership of certain coal mines, to the extent that the portion of company-owned coal is a

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[30] S*ee e.g.,* "An Analysis of Price Volatility in Natural Gas Markets," US Energy Information Administration, Office of Oil and Gas, August 2007, Washington DC. *Also see* Direct Testimony of Gregory N. Duvall on Behalf of Rocky Mountain Power, 3:52-60, filed in UPSC Docket No. 09-035-15.

[31] Even years with similar weather occurrences can influence market prices for natural gas differently depending on other market conditions. *See e.g.,* "Impact of the 2008 Hurricanes on the Natural Gas Industry," US Energy Information Administration, Office of Oil and Gas, January 2009, Washington DC. *Also see:* "2006 State of the Markets Report," FERC, Washington DC.

[32] *See e.g.,* C. Whitmore, "Electric Power Markets in the West and Southwest," Office of Enforcement, Division of Energy Market Oversight, Federal Energy Regulatory Commission, July 1, 2008.

declining part of the portfolio other factors discussed in this response become more important. Even renewable generation has a degree of volatility associated the intermittent nature of many renewable resources. All of these factors suggest that fuel costs will be volatile as is shown in this testimony.

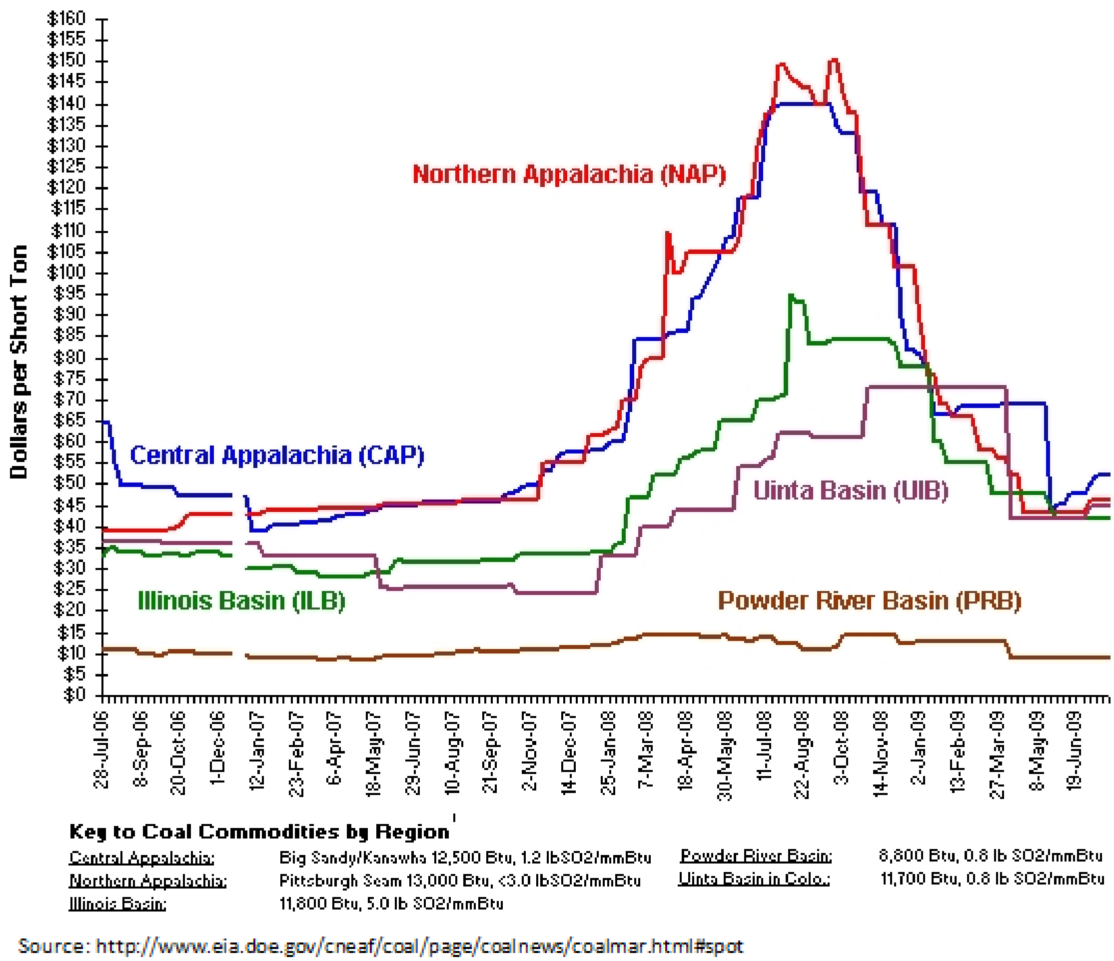


Figure 4: Spot Market Prices for Coal (July 2006 – June 2009)

Second, the demand for electricity can be volatile and unpredictable as it depends on a number of factors including weather patterns, income levels (affected by general economic conditions), energy efficiency investments, prices of alternatives, and even expectations of the future. A public utility, however, unlike a private non-regulated firm, cannot refuse to meet this fluctuating customer demand as long as customers are willing to pay rates set by the regulatory body. Rocky Mountain Power must obtain power and energy to serve customers despite the fact that it might lose money on incremental sales. Because the utility cannot refuse service requests or unilaterally change its prices to reflect changing conditions, it cannot manage the uncontrollable factors such as weather and commodity market prices. This adds to the uncertainty of procuring power and energy for consumers due to the factors cited in this answer.

Third, the supply of electricity depends on resource availability and transmission system concerns both of which have inherently uncertain aspects. This uncertainty, along with other issues, has lead the Northwest Power and Conservation Council to state that "electricity prices also exhibit substantial random variations due to conditions in other parts of the interconnected West and other factors that are not explicitly considered."[33]

Fourth, the volatility of the NPC can be shown through a statistical approach. For example, comparing total non-fuel operation costs and fuel costs for the entire industry we see that fuel costs are more volatile than non-fuel costs as measured by the coefficient of variation. (See Table 1) I find a similar result using FERC Form 1 data. (See Table 2) NPC for PacifiCorp are roughly two times as volatile as non-power costs. Table 2**,** however, understates the volatility in NPC that Rocky Mountain Power faces today. For example, when we look at the last seven years (i.e., 2002-08),[34] NPC for PacifiCorp are roughly four times as volatile as

[33] Northwest Power and Conservation Council, "The Fifth Northwest Electric Power and Conservation Plan," May 2005, p. 6-4.

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

non-power costs driven largely by increases in the volatility of fuel expenses (power purchases have been less volatile during this period). (See Table 3) I understand that the Company has added several natural gas plants in the last few years. Given the price volatility of natural gas, we should expect that fuel expense will become more volatile as more gas plants are added to the portfolio.

Table 2: Summary Statistics for Net Power Costs (PacifiCorp, 1992-2008)

Cost Category	(A) Mean (Millions USD)	(B) Standard Deviation	(C) = (B) / (A) Coefficient of Variation
Total Expenses	2,321	757	0.33
Fuel	569	170	0.30
Purchased Power	830	564	0.68
Sales for Resale	920	474	0.51
Wheeling	74	23	0.31
Net Power Costs[a]	553	244	**0.44**
Non-NPC Expenses[b]	769	177	**0.23**

Source: FERC Form 1 Note: Form 1 data may differ slightly from data provided to Rocky Mountain Power Witness Graves.
a. NPC calculated as: Fuel (FERC accounts 501, 503 and 547) plus Purchased Power (FERC account 555) plus Wheeling Expense (FERC Account 565) less Sales for Resale (FERC account 447)
b. Non-NPC calculated as Total Expenses minus Fuel, Purchased Power and Wheeling Expenses for each year. 1998 NPC adjusted by $1.3 Billion to reflect accounting for “book outs” transactions in account 557.

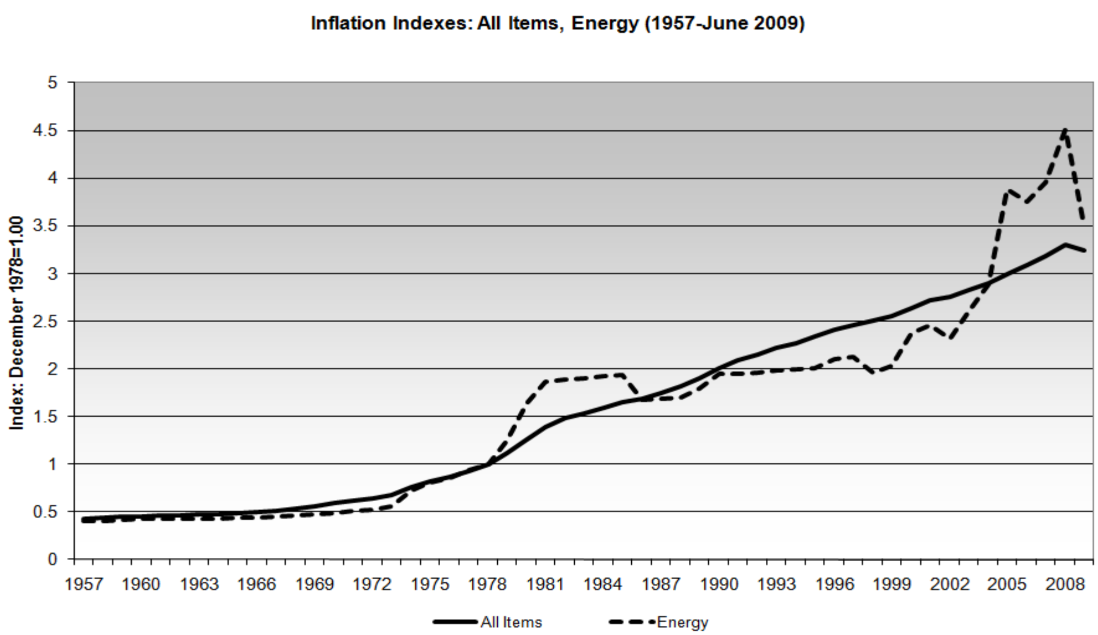
Table 3: Summary Statistics for Net Power Costs (PacifiCorp, 2002-2008)

Cost Category	(A) Mean (Millions USD)	(B) Standard Deviation	(C) = (B) / (A) Coefficient of Variation
Total Expenses	2,427	357	0.15
Fuel	662	243	0.37
Purchased Power	730	187	0.26

Sales for Resale	771	236	0.31
Wheeling	91	17	0.19
Net Power Costs[a]	712	227	**0.32**
Non-NPC Expenses[b]	944	82	**0.09**

Source: FERC Form 1 Note: Form 1 data may differ slightly from data provided to Rocky Mountain Power Witness Graves.
a. NPC calculated as: Fuel (FERC accounts 501, 503 and 547) plus Purchased Power (FERC account 555) plus Wheeling Expense (FERC Account 565) less Sales for Resale (FERC account 447)
b. Non-NPC calculated as Total Expenses minus Fuel, Purchased Power and Wheeling Expenses for each year.

If we take a slightly different statistical approach and look at the price of energy compared to the overall inflation for consumer goods, we find that energy prices appear more volatile. (See Figure 5) Indeed, the volatility in energy prices appears to coincide with the first oil embargo in the early 1970s and has continued to the present time.



Source: *Bureau of Labor Statistics*

Figure 5: Inflation Indexes All Items and Energy (1957-2009)

Fifth, regulators recognize that fuel costs, especially as power markets and natural gas have become an important part of the utility portfolio, are inherently volatile. The Missouri Public Service Commission came to this conclusion in the Union Electric case cited earlier.[35] Other regulators have made this same conclusion. For example, the Louisiana Public Service Commission states that the "[ECAM]…has been established due to the materiality and historical and potential volatility of these costs."[36] More recently, the Arizona Commission found that an ECAM:

> …is fair and reasonably designed to permit [the utility] to recover the volatile costs of its purchased power and fuel used to supply retail electric power. Although [the ECAM] does not contain a cap or 90/10 sharing arrangement, it contains the added protection that the…[ECAM]…will not be modified except by Commission order. Each year the Commission will be able to consider the effects of a potentially disruptive spike in fuel costs in the context of current events, which allows the Commission to determine the best course of action at the time, instead of relying on a cap that may or may not protect ratepayers.[37]

Finally, in Rocky Mountain Power's ECAM filing in Idaho, implementation was stipulated to by the staff of the Idaho Public Utilities Commission. In supporting the stipulation Idaho Staff noted that the ECAM:

> …is justified based on the volatility of power supply costs experienced by the Company in between rate cases and the current inability of the Company to adjust its rates in a timely manner to reflect that volatility.[38]

Q. What do you conclude about the volatility of Rocky Mountain Power's NPC?

A. The evidence strongly supports the conclusion NPC are significantly more volatile than non-NPC expenses and have become more volatile in the recent past.

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[35] Missouri Public Service Commission, *supra* note 17.

[36] Before the Louisiana Public Service Commission, "Development of standards governing the treatment and allocation of fuel costs by electric utility companies," General Order, Docket No. U-21497, October 1, 1997.

[37] Arizona Corporation Commission, Tucson Electric Power, Decision No. 70628, p. 39, December 2008.

[38] Idaho Public Utilities Commission, Direct Testimony of Randy Lobb in Case No. PAC-E-08-08, 2:7-11, July 31, 2009.

Q. Are NPC largely beyond the control of utility management?

A. To a large degree yes. I first note that the NPC at issue in this case are made up largely of fuel expenses and net purchased power. With limited exceptions, utilities purchase fuel in commodity markets. Market prices in fuel markets are determined by the interaction of supply and demand; all buyers are *price takers* (i.e., no control over the price). Power markets operate the same way. Rocky Mountain Power has no control over the price set in power markets and therefore it has no control over the prices that are paid for purchased power or the selling price. NRRI states that:

> Unless a utility is vertically integrated so that it owns the fuel source…it is unlikely that the utility can exert much control over the cost of the fuel. This does not mean that it has no control whatsoever, or that it is excused from hard-nosed, tough bargaining. Indeed, state public utility commissions often hold utilities to a standard of care of a prudent business man in negotiating fuel contracts before allowing the cost to flow through a fuel adjustment or purchased gas adjustment clause. In theory, at the margin a prudent utility would incur costs in searching for less expensive fuel supplies equal to its expected benefits, that is the expected cost savings. The conclusion seems clear that unless the utility owns an affiliated fuel source, it still has little or no control over the market price of fuel. However, it may have control of its total cost of fuel because it can change the mix of its fuel supplies.[39]

Q. Does the fact that the Company owns coal mines diminish the need for an ECAM?

A. No. First, the price of coal may be regulated and therefore set in advance, but the quantity of fuel used is related to demand that is not under the control of the utility. Second, the question of whether a utility acquires resources from a company-owned source or on the market is a strategic decision that is largely independent of the need for an ECAM as I discuss later in this testimony. Finally,

[39] NRRI, *supra* note 21, p. 4.

even if coal costs were relatively stable as a result of vertical integration, those costs would be included in the base NPC in rates and would have no effect on the ECAM surcharge.

Q. Are there any other reasons why a utility's NPCs are largely outside its control?

A. Yes. An electric utility, at least in Utah and other states that have not restructured the market, has an obligation to serve its customers and has little or no control over the demand on the system at any given time. While traditional load control and other demand-side management exist, the vast majority of demand on the system cannot be influenced by the utility. To the extent that demand has random fluctuations, the power costs associated with meeting those random fluctuations are basically out of the utility's control. (I note that this does not suggest that Rocky Mountain Power's forecasting approach is suspect, for the most part forecasting costs using a general trend analysis is sufficient to support a future test year as long as the costs that are being projected are not large, volatile, and largely beyond the control of the utility.)

Q. Do utilities have control over the total cost of NPC?

A. To some extent a utility can make decisions that have an influence on total NPC, as opposed to the individual prices paid for fuel and power. For example, as noted in the NRRI quote in the previous response, utilities have some control over the mix of fuel. In addition, utilities can undertake hedging activities, both physical and financial, that will certainly have some influence on total fuel and net purchased power costs. Finally, utilities can vertically integrate into fuel supply.

Q. Do you still claim that utilities have little or no control over NPC?

A. Yes, at least in the context of recovering net power costs through an ECAM. We have to understand what is meant when we say that a utility has little or no control over NPC. Once a set of prudent decisions has been made about the types of power plants that a utility deploys and its approach (or tolerance) for hedging fuel and purchased power, the resulting costs are essentially the cost of the commodity to run the set of plants the utility owns and to purchase the power necessary to meet its obligation to keep the lights on. Regulators have recognized that utilities have limited control over fuel costs. For example, the California regulator recognized this fact over 35 years ago when approving a fuel clause for Southern California Edison:

> The area of costs in which the fuel clause would operate are areas in which the utility has relatively little control once the choice of generating facility is made, the fuel character is determined by governmental regulations or other environmental consideration, and long-term fuel supply arrangements are set.[40]

Decisions about the mix of plants to build are *strategic* decisions, not operational decisions. These strategic decisions are reviewed by the regulator either in a prudence review or a least cost plan. Once a utility's strategic decisions are deemed prudent, however, the cost of implementing those strategic decisions is largely out of the control of management. As the Colorado Commission has noted, ECAMs "permit[s] rapid recovery of increased costs over which the utility has no control."[41]

[40] California Public Utilities Commission, *Re: Southern California Edison Company*, Decision No. 79838, March 21, 1972.

[41] Public Utilities Commission of the State of Colorado, s*upra* note 18.

I do not want to be misunderstood. I am not suggesting that the UPSC pass through any cost that Rocky Mountain Power claims in an ECAM filing. Quite the contrary, the ECAM does not guarantee one penny of cost recovery as the utility will still need to demonstrate prudent operation. I agree, then, with the Kansas Corporation Commission when it identified one of the key benefits of ECAM ratemaking is related to the concept that NPC are:

> …largely outside the control of the utility…[and]…ultimately must be passed through to the consumer, and an appropriately designed…[ECAM]…with proper safeguards, is the most efficient method to accomplish this pass-through.[42]

In sum, there is justification for recovery of prudently incurred costs through an ECAM partially because the utility management has little or no control over the prices it pays for fuel and power. To the extent there is any control by utility management over total fuel costs, that discretion must be reviewed by the regulator.

V. ECAM Ratemaking Is Standard Practice for State Utility Regulatory Bodies

Q. Does the ECAM proposal represent a radical departure from standard regulatory practice?

A. No. When viewed from the perspective of the length of time state regulators have employed ECAMs and the near unanimous use of these mechanisms.[43]

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[42] Kansas Corporation Commission, Order in Docket No. 106,850-U, April 19, 1977, p. 14.

[43] It is my understanding the UPSC approved the request by the Company to remove its energy balancing account mechanism in 1992. (UPSC Docket No. 90-035-06) Therefore Utah has endorsed using an ECAM-type mechanism in the past when the operating environment warranted such an approach and removed it when conditions changed.

Q. How long has an ECAM-type mechanism been used in the United States?

A. ECAMs were widely used following World War I to address issues with increasing input prices, namely coal.[44] In the late 1940s, ECAMs were applied to 86 of the 100 largest electric utilities and by the late 1950s forty-four states used ECAMs.[45] The Edison Electric Rate Book for 1957 indicates 40 states plus Washington DC were employing ECAMs and 37 states plus DC had adopted Purchased Gas Adjustment clauses. In a 1974 study of all 51 jurisdictions (including DC), NERA found that 42 states had approved some form of a fuel-adjustment clause.[46] NRRI found that 44 of the jurisdictions were using some form of fuel adjustment charge by 1978.[47] In a later study, NRRI found that 41 jurisdictions had "long-standing" ECAMs, defined as having been in place greater than five years.[48] That fuel adjustment charges have been part of the American electric utility regulatory structure for many years is beyond question.

Q. Is the ECAM still a common method of addressing fuel and purchased power costs?

A. Yes. In Exhibit RMP____(KAM-2S), I report a survey of all US jurisdictions that regulate investor-owned electric utilities. (Figure 6 provides a graphical representation of Exhibit RMP____(KAM-2S)). In this study I consider 36 jurisdictions as "non-restructured" meaning that either restructuring never

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[44] R.S. Trigg, (1958). "Escalator Clauses in Public Utility Rate Schedules," *University of Pennsylvania Law Review,* 106, pp. 964-97. Trigg claims that by "the middle of the 1920's [the FAC] was a recognized and widely accepted method of utility rate-making…"

[45] Trigg, *supra* note 44.

[46] NERA, (1974). "The Fuel Adjustment Clause: A Survey of Criticism, Justifications, and its Application in the Various Jurisdictions."

[47] K. Kelly, T. Pryor, and N. Simons Jr., (1979) *Electric Fuel Adjustment Clause Design*, NRRI.

[48] NRRI, *supra* note 21, p. 109 (this count includes Washington DC and FERC).

occurred in the jurisdiction (32) or the state has substantially moved away from restructuring (4). (I include Oregon in the non-restructured group despite Oregon's approach to restructuring, i.e., allowing some large customers to choose suppliers. The major utilities in Oregon, including PacifiCorp, remain vertically integrated with electric generation in rate base.) Of these 36 jurisdictions, 35 have implemented a fuel adjustment charge, at least for one electric utility, with Utah the lone jurisdiction in the United States that does not currently have a ECAM. In the remaining 15 jurisdictions (including Washington DC), Nebraska does not regulate investor-owned electric utilities and 14 can be considered restructured in the sense that generation is not owned by the regulated utility. For those 14 states that have restructured according to this definition, all have some form of a power cost pass-through mechanism that passes the cost of procuring power (i.e., the market price) directly through to end use customers. (Often this is referred to as Standard Offer Service or Default Service.)

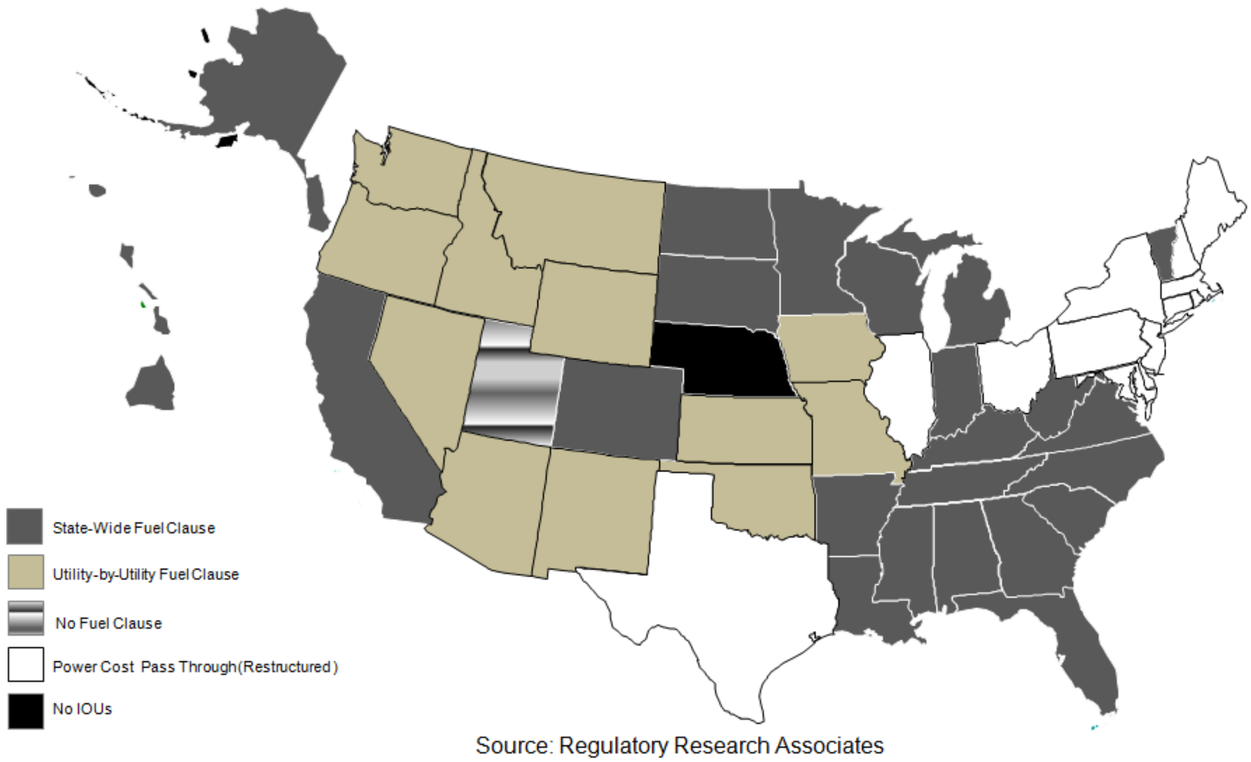

Figure 6: The Use of ECAMs in the United States (July 2009)

Q. Are there any recent examples of jurisdictions moving toward using an ECAM?

Yes. Since early 2007 there have been 11 ECAMs in 8 different jurisdictions that have been approved as shown in

Table 4. In addition, Rocky Mountain Power has a settlement pending before the Idaho Public Utilities Commission that, if approved, would establish an ECAM similar to the one proposed in this case.[49]

Table 4: Recent ECAMs

State	Utility	Date
Arizona	Tucson Electric Power	Dec-08
Missouri	Empire Electric	Jul-08
Missouri	AmerenUE	Feb-07

[49] ECAM Stipulation filed in Idaho Public Utilities Commission Case No. PAC-E-08-08, June 29, 2009.

Missouri	Aquila	May-07
Montana	MDU Resources	Apr-08
New Mexico	PS New Mexico	May-07
Oregon	Portland General	Jan-07
Vermont	Central Vermont PS	Sep-08
Virginia	Potomac Edison	Apr-08
West Virginia	Monongahela Power	May-07
West Virginia	Potomac Edison	May-07

Q. Outside of Utah are there any major electric utilities that do not have ECAMs?

A. I am aware of only two cases. It is my understanding that MidAmerican voluntarily eliminated its Iowa and Illinois fuel and energy adjustment mechanisms as part of the elimination of traditional rate-base, rate-of- return rate regulation for that utility in those states. I am also aware that Kansas City Power and Light has agreed to a long-term energy plan in which a fuel adjustment charge does not apply to portions of its Missouri service territory.

VI. RESPONSE TO SPECIFIC QUESTIONS RAISED BY THE PARTIES

Q. Would you please summarize your conclusions from this section of your testimony?

A. After reviewing the comments of the parties I conclude that most if not all of these questions have been addressed by nearly every regulator that has approved an ECAM. (Recall that every state that retains regulatory control over vertically integrated electric utilities has approved some form of an ECAM, with the lone exception of Utah.) All of the questions raised by the parties are reasonable areas for inquiry and the Commission should carefully review the responses. After an objective review, however, one must come to the conclusion that the ECAM proposal is a justified approach to recovering net power costs. Below I will address certain specific questions raised by the parties.

Q. Which parties are you responding to in this section of your testimony

A. While I am not responding to every question raised by the parties, I will respond to questions related to the purpose of my testimony. I have reviewed the comments, and respond to certain questions raised by the Commission,[50] the Utah Division of Public Utilities ("DPU"); the Utah Office of Consumer Services ("OCS"); the Utah Industrial Energy Consumers ("UIEC"); the Utah Association of Energy Users ("UAE"); Salt Lake Community Action Program ("SLCAP"); and Western Resource Advocates and Utah Clean Energy ("WRA-UCE").

A. The Incentive to Operate Efficiently

Q. Does an ECAM reduce the incentives of the utility to carefully plan and operate its fuel and energy procurement operations? (UPSC Order pp. 9-10, DPU pp.3-4; UAE, ¶3;UIEC ¶5; WRA-UCE ¶1; SLCAP, p. 2)

A. I know of no direct evidence to suggest this is the case, at least for ECAMs that have a regulatory review process, yet this is perhaps the single most common question about ECAM ratemaking. While much of the response to this question depends on an understanding of the details of procurement incentives inherent in the current system, often such nuanced understanding can be difficult to convey in a litigated proceeding. There are, however, concrete reasons to believe that ECAM ratemaking is not likely to change the utility's approach to purchasing fuel or power.

[50] UPSC Notice of Scheduling Conference and Procedural Order in Docket 09-03-15, June 18, 2009 ("USPC Order"). I note that several of the Commission's questions have been addressed in prior portions of my testimony.

First, as shown above, the prices paid for fuel and power are not within the control of the utility, as a result the utility has little ability to improve its efficiency of purchasing above its prudent practices. For example, if the utility has to purchase 20 MW in the next hour to meet its demand it will pay the market price as a result of its obligation to serve. This will occur with or without an ECAM. The ECAM allows the utility to focus on those costs that are controllable to the utility and does not penalize the utility (or customers) for costs that are outside management's control.

Second, elsewhere I have provided a survey of ECAM practices around the U.S.; from that research I am unaware of any jurisdiction that has removed an ECAM due to a concern over lowered utility efficiency.[51] There are some limited cases where a jurisdiction has attempted to implement efficiency mechanisms as part of the ECAM ratemaking, but the basic ECAM procedure has not been abandoned for this reason in any jurisdiction to my knowledge. (From RMP___(KAM-2) I am aware of only four jurisdictions that have specific incentive mechanisms in the ECAM. There are nine others that have some form of partial cost recovery.)

Third, the Commission will review the utility procurement methods for reasonableness under the ECAM. If the utility acts imprudently, the Commission can deny cost recovery for such costs. This is the same incentive that other functions of the utility operate under and therefore we should not expect that the incentive to operate efficiently is any weaker here. There are numerous examples

[51] There was some concern in the early years of ECAMs that utilities could use the lessened review process of some of the early ECAMs to earn profit, although this issue has not been prevalent in recent ECAM proceedings. This cannot occur with the proposed ECAM design as the Rocky Mountain Power will, at best, recover its prudently incurred costs.

of regulators disallowing costs in fuel adjustment proceedings over the past twenty years. This suggests that regulatory bodies are fully capable of reviewing fuel adjustment data and procurement procedures of utilities.

Fourth, ratemaking is designed to set a fair price that balances the needs of the utility and the customers. Incentives aside, any party that claims utilities should not be allowed an opportunity to recover unavoidable and prudently incurred costs, should have the burden to demonstrate how such a process furthers the goals of regulation or benefits consumers. Providing incentives for efficiency should be a goal of regulation, but that goal has to be balanced against other goals such as providing utilities with an opportunity to recover prudently incurred costs and assuring that customers pay no more than prudently incurred costs.

Last, some have claimed that the ECAM relieves the utility from the discipline of the market. (*See e.g.,* UIEC ¶5) This claim misunderstands the current regulatory structure. Rocky Mountain Power is not benchmarked to a market price, but rather a forecast of NPC. While that forecast may be the best guess at the time of how markets *might* turn out, commodity markets and demand conditions are volatile and forecasts can never replicate the market in such an environment. (Not to mention that the NPC is determined through an administrative process, subject to the natural give and take of an administrative proceeding.) This claim does not justify rejection of the ECAM. Moreover, "market discipline" does not mean that market prices are always fixed. Airlines, coffee shops, automakers, and most other firms face a market price and therefore are disciplined by the market. Yet prices change in these markets all the time. General inflation causes prices to change and no one believes that any one firm in a competitive market has control over the general price level and most of us understand that when inflation occurs we expect market prices for the goods and services we buy to increase. As input prices increase, the price in the market must increase as marginal costs increase (recall that market prices are set based on marginal cost). There is no economic efficiency loss nor is there a reduction in incentives to minimize cost when prices increase (or decrease) in a market due to increasing (or decreasing) marginal costs for the industry. Indeed, efficiency is enhanced when prices are allowed to reflect the (changing) marginal cost of production.

Q. Does an ECAM reduce the incentives to substitute low or no marginal cost resources for higher marginal cost resources or to engage in energy efficiency? (DPU pp.5-6; WRA-UCE ¶1; UAE ¶6)

A. Not if regulation is designed to be fair to both the utility and customers. The ECAM is designed to recover expenses, not provide the utility with additional profit. Profit in the traditional regulatory paradigm comes from the capital investment of the utility. An ECAM has no influence on the decision to build a coal or wind plant; that decision is made in a least cost planning exercise and reviewed when rates are set. The utility is no better off, from the perspective of profit, from running a coal plant as opposed to a wind farm with an ECAM in place. While some may feel the utility should build more wind or solar (or coal for that matter), denying the utility cost recovery for prudently incurred costs is not the proper public policy to promote any generation resource over another. The choice of which resources to build is a question for a least-cost planning process where capital costs and operation characteristics can be properly evaluated.

Furthermore, I understand that Rocky Mountain Power has a separate recovery mechanism and process for implementing energy efficiency investments. In April of this year, Rocky Mountain Power, in coordination with the Utah Division of Public Utilities and the DSM Advisory group, filed proposed changes to the standards and guidelines for evaluation of the costs and benefits and prudency of energy efficiency programs in response to a Commission directive.[52] There is no reason to believe that the existence of the ECAM will alter the use of these guidelines either by Rocky Mountain Power or the Commission. Moreover, energy efficiency is a strategic decision—much as building a power plant. Costs and benefits of energy efficiency measures are calculated and the utility purchases some level of energy efficiency according to guidelines. If the utility is not acting prudently or does not follow guidelines, then the Commission will take this into account when deciding on resource acquisition and cost recovery. As I understand the ECAM proposal, it will not change this process. Nearly every jurisdiction has an interest or requirement to promote energy efficiency. I am unaware of any jurisdiction that has removed an ECAM related to a perceived bias in resource choices as a result of ECAM ratemaking. Again, there is no need to speculate about what a utility may or may not do in the future; the Commission can review actual results and determine if adjustments are needed.

[52] USPC Docket No. 09-035-27. The Commission's directive is UPSC Order in Docket No. 07-035-T04, April 2, 2007.

B. An ECAM Is the Most Reasonable Alternative to Ensuring a Fair Rate

Q. Are there other options that could be implemented that would address the issues raised by the ECAM proposal? (UPSC Order pp. 9-10, DPU p. 3; UAE, ¶1; WRA-UCE ¶2; OCS, p. 4)

A. I do not believe that any other option is preferred to the ECAM proposal in this case. I have several reasons for this conclusion. First, an obvious fact exists suggesting that the ECAM is the best approach—the nearly unanimous adoption of the process by state regulators. Moreover, the options for cost recovery mechanisms are relatively limited, at least inside of the traditional cost-based regulatory paradigm. (I am assuming that alternatives to cost-based regulation are not part of this current discussion.) Certainly the *status quo* is one option; the evidence in this case suggests that that process has not been effective.[53] Even assuming the *status quo* option could address the issues raised by this case, which does not seem likely, at a minimum, frequent rate cases may continue to be necessary over the long term. The Kansas Corporation Commission addressed why the option of more frequent rate proceedings is unworkable in approving ECAMs for the state:

> In rejecting this alternative, the Commission feels that it is important to note that, unless periodic hearings are quite frequent (which would necessitate increased regulatory costs to the consumer), significant regulatory lag would be introduced, and the cash requirements of the utilities would be increased. We do not believe that the introduction of increased regulatory lag serves any useful purpose, either to the utilities or the consumers. If the costs of energy are significant and are legitimate costs that will be incorporated into the rate structure at a formal hearing, then those costs should be passed on equitably to the consumers without

[53] Duvall, *supra* note 29.

> undue delay. This will insure that the utility is allowed the opportunity to recover its costs and earn a fair return on its investment.[54]

The KCC further made the observation that to “disallow…[ECAM ratemaking]… in favor of periodic hearings constitutes a denial that a problem exists, rather than a valid attempt to deal with the realities of changing energy costs and their impact on the utilities and their customers.”[55]

Other options could take the form of accelerated rate cases, immediate pass-through of all costs subject to refunds, or an adjustment clause that allows for less than full recovery of prudently incurred costs or includes performance metrics. (I will address these last two options in my next response.)

Accelerated rates cases are used infrequently and would require additional evaluation on the part of the Commission as this would include all costs factors in the revenue requirement. Interim rates subject to refund are also infrequently used in most jurisdictions, largely because these mechanisms are considered emergency actions not to address on-going cost changes. I understand that immediate rate relief subject to refund is authorized in Utah, yet this mechanism has not been typically employed except in emergency situations.[56] This conforms to my experience in other jurisdictions. In addition, any full rate case approach ignores one of the benefits of a limited adjustment clause, namely the limited review that is necessary. In the long run, there may well be years when no rate change is necessary other than to adjust for NPC; requiring a full rate case to adjust for NPC would create a more cumbersome regulatory process.

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[54] Kansas Corporation Commission, *supra*, note *42*.

[55] Kansas Corporation Commission, *supra*, note *42*.

[56] Duvall, *supra* note 29.

Q. Is it necessary to implement productivity or other performance measures in the ECAM? (UPSC Order pp. 9-10, WRA-UCE ¶2; UIEC ¶5; OCS, p 4; SLCAP, p. 2)

A. No, not at this time. There are several reasons for this conclusion. First, let me address any proposal that would arbitrarily deny cost recovery by providing only partial recovery of prudently incurred costs in the name of improving incentives. In reviewing such a proposal we should keep the following question in mind: Why should a utility be denied the opportunity to recover all of its prudently incurred costs? The purpose of regulation is set fair prices that balance the interests of consumers and utilities, if we agree that these are prudently incurred costs then what purpose does it serve to require shareholders to bear the burden of these costs? (Of course, imprudently incurred costs are a different matter and shareholders should bear that risk.) We would not insist that only 95 percent of the Commission-approved increase from a rate proceeding be included in rates (although one might try to claim incentive benefits from such an approach). The Florida Public Service Commission addressed this issue over 35 years ago in approving an ECAM:

> Initially we note that…[sharing of fuel costs between ratepayers and shareholders]…defeats the very purpose of the clause, that is, to allow the companies to recover their fossil fuel costs. Moreover, it can ultimately work to the detriment of the ratepayer when fuel costs are falling and the utility is not required to pass on the full amount of the reductions, but instead would be allowed to retain a portion of the reductions. We also prefer to view such a proposal as a penalty rather than an incentive and we have serious doubts as to our legal authority to arbitrarily preclude a public utility from recovering a legitimate operating expense through the ratemaking process.[57]

[57] Florida Public Service Commission, Order No. 6557, November 26, 1974.

Second, standards or metrics, such as target heat rates, embedded in an ECAM that link utility cost recovery to performance has some intuitive appeal just as performance-based regulation (e.g., price caps or earning sharing) has an appeal to address the perceived incentives inherent in the traditional regulatory paradigm. The intuitive appeal, however, rests mostly on the *assumption* of poor behavior and that utility management can influence these costs. There is no reason to assume, *a priori*, that the proposed ECAM will produce a less efficient utility. As I have noted above, there are good reasons to think that the ECAM will not change the utility behavior much if at all, and there is also no reason to believe that the Commission's prudence review of the utility's behavior will fail to protect the public interest.

Third, designing incentive mechanisms can be complicated by the need to avoid unintended consequences, such as promoting one resource over another. Again, we can look to the actual practice of ECAMs in the U.S. to see if regulators have been concerned enough about this issue to implement performance requirements. As I noted elsewhere, few jurisdictions have explicit performance standards even though many of these jurisdictions have had ECAMs in place for many years, even decades.

Finally, while it is impossible to claim that ECAMs will produce perfectly efficient utilities, this is also true for the *status quo*. I recommend that the Commission approve the proposed ECAM and review this issue over time. If the Commission finds its review process, and any prudence disallowances it might make, does not provide sufficient incentive for efficient operations then it can revisit the issue at that time.

Q. Are there any other approaches that might be used to address volatile costs? (UPSC Order pp. 9-10, DPU, p.3; WRA-UCE ¶2; OCS p. 4; SLCAP, p. 2)

A. I do not believe that any other mechanism is appropriate in this case. For example, one approach that some have suggested involves addressing the volatility of these costs through market mechanisms, perhaps by requiring the utility to hedge 100 percent of its annual portfolio. I see problems with this approach in Utah.

First, and beyond the question of restructuring, there is no practical possibility of hedging all purchased power and fuel costs. The volatility associated with energy demand and the thin market for shaped products makes this a practical impossibility.[58] Second, it is not clear that hedging 100 percent would be possible or desirable in this context. Hedging is not costless. While there may well be a value to completely fixed prices, that value would have to be compared to the cost of obtaining fixed prices. Volatile prices do not necessarily equate to higher prices, at least on average. That is, we should expect that hedging, on average, would increase the cost of purchasing fuel and power as counterparties to hedges must be compensated for assuming the risk of price volatility from which we think end-use customers should be sheltered. By using an ECAM process to address some of the price risk, it is quite possible that customers will face lower overall prices, on average, compared to requiring the utility to attempt the impossible, at least in Utah, by hedging the entire price risk inherent in fuel and

[58] Graves, *supra* note 29.

power markets. To the extent that the Commission directs that prices for fuel and power should be hedged, and therefore are known and can be placed in base rates, those costs will never show up in the ECAM adjustment process. To the extent that on-going hedging is deemed prudent by the Commission the ECAM only captures those costs that are prudently incurred and not included in base rates.

C. Miscellaneous Issues

Q. Will the ECAM increase the administrative cost of regulation? (UIEC ¶3; OCS, p. 3; UAE ¶9)

A. Over the long term the ECAM will likely reduce administrative costs. Many observers and regulators have identified lower administrative costs as one of the key benefits attributed to ECAM ratemaking.[59] Most often the reason for this claim is that prices reflect costs without the need for a full blown rate case. Clearly this has been the case for periods when rate cases were less prevalent. Adoption of an ECAM does not remove prudence review function of the Commission for NPC. There is, however, a major difference between the status quo and an ECAM. Under the current approach, the accuracy of the forecast of NPC in rate cases is litigated in a rate case. This issue should become far less significant than it is today in rate cases as the focus of the prudence of Rocky Mountain Power's NPC will shift to separate ECAM proceedings. Initially, this might either increase or decrease the cost of regulation depending on the approach of regulators and other interested parties. Experience in other states suggests that over time regulators and other interested parties become quite efficient at

[59] *See e.g.,* NERA *supra* note 46; NRRI *supra* note 47. Many of the regulatory orders cited in this testimony also note this as one of the benefits of ECAM ratemaking.

identifying areas of NPC to review and are able to focus their attention on a few issues that require scrutiny. Therefore, over a long period of time we should expect lower administrative costs.

I caution, however, that the cost of regulation should not be the sole factor in determining whether a mechanism is justified. We must assume that there is a benefit from regulating utilities that outweighs the costs associated with that regulation. If the mechanism is justified from other perspectives, we should not be held up by the concern over additional regulatory costs that may or may not appear in the future.

Q. Do ECAMs address rate stability? (DPU, p. 6; SLCAP, p. 2; UAE ¶7)

A. No. The purpose of an ECAM is to better match costs with prices; often this requires prices to change in order to better reflect costs. Therefore rate stability is sacrificed, to some extent, to obtain better price signals and provide the utility with an opportunity to recover its prudent costs. As an economist, I favor better matching of prices with costs. There is good scientific evidence to suggest that society benefits when prices and costs are connected. As a former regulator, I understand that price stability considerations enter into the determination of just and reasonable rates. (I understand price stability is an objective of Utah ratemaking along with the maintenance of the financial integrity of the utility.)[60] There is no guarantee, however, that traditional regulation will promote perfect rate stability. For example, the UPSC has approved rate changes for Rocky

[60] Utah Code 54-4a-6(4) (a) and (e).

Mountain Power 20 times since January 2000.[61] Many of these rate changes **lowered** rates for consumers. I also understand that PacifiCorp has recently filed for a reduction of over 5 percent in its energy cost adjustment clause in California.[62] This shows that price changes do not necessarily hurt consumers unless those changes are not reflective of the actual costs of providing service. The question of how much price stability to purchase is a social choice, but if price stability is purchased the costs of purchasing that stability must be borne by those who benefit—namely customers. Price stability should not be purchased for customers by requiring investors to pick up the tab for NPC volatility and unpredictability.

Q. Does this conclude your direct supplemental testimony?

A. Yes.

[61] "Rate Changes" 6-16-09 for Utah Power/Rocky Mountain Power, 03-057-T01, Utah Public Service Commission, (http://www.psc.state.ut.us/Rate%20Changes%20Electric%206-09.pdf, accessed August 3, 2009).

[62] *In the Matter of the Application of PACIFICORP (U 109 E), and Oregon Company, for Authority to Update its Rates Pursuant to its Energy Cost Adjustment Clause Effective January 1, 2010*, Application No. 09-07-__, filed July 31, 2009 with the California Public Utilities Commission.