STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of	**)**	
Rocky Mountain Power for	**)**	**Docket No. 09-035-15**
Approval of its Proposed Energy	**)**	**Witness OCS -3D**
Cost Adjustment Mechanism	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE UTAH OFFICE OF CONSUMERS SERVICES

Resource Insight, Inc.

NOVEMBER 16, 2009

REDACTED

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further described in Exhibit OCS____(PLC-1).

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and ninety times on utility issues before various regulatory, legislative, and judicial bodies, including the Arizona Commerce Commission, Connecticut Department of Public Utility Control, District of Columbia Public Service Commission, Florida Public Service Commission, Maryland Public Service Commission, Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Michigan Public Service Commission, Minnesota Public Utilities Commission, Mississippi Public Service Commission, New Mexico Public Service Commission, New Orleans City Council, New York Public Service Commission, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utilities Commission, Rhode Island Public Utilities Commission, South Carolina Public Service Commission, Texas Public Utilities Commission, Utah Public Service Commission, Vermont Public Service Board, Washington Utilities and Transportation Commission, West Virginia Public Service Commission, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission.

Q: Have you testified previously before the Commission?

A: Yes. I testified on behalf of the Utah Office of Consumer Services (or its predecessor, the Committee of Consumer Services) in the following dockets:

- Docket No. 98-2035-04, on the proposed acquisition of PacifiCorp by Scottish Power. My testimony addressed proposed performance standards and valuation of performance.

- Docket No. 99-2035-03, on the sale of the Centralia coal plant. My testimony addressed the costs of replacement power, the allocation of plant sale proceeds, and the potential rate impacts on Utah customers of PacifiCorp's decision to sell the plant. I testified that the sale of Centralia was not in the interest of ratepayers and that if the Commission approved the sale it should allocate more of the sale proceeds to Utah to mitigate potentially high replacement power costs. The Commission adopted this latter recommendation as part of approving the sale.
- Docket No. 07-035-93, on the reasonableness of cost-of-service study, rate spread and residential rate design proposals of PacifiCorp, which now operates in Utah as Rocky Mountain Power (RMP).
- Docket No. 09-035-23, on RMP's cost-of-service study.

I also assisted the Office of Consumer Services in analyzing various issues in the multi-state process. These issues included resource planning, cost allocation of generation-and-transmission plant, regulatory policy and risk analysis.

II. Introduction

Q: On whose behalf are you testifying in this rate case proceeding?

A: My testimony is sponsored by the Office of Consumer Services (Office).

Q: Please summarize your understanding of the purpose of this phase of the proceeding.

A: The Public Service Commission has bifurcated this proceeding into two phases. This first phase will consider whether an energy-cost-adjustment mechanism (ECAM) is needed and in the public interest (Docket No. 09-035-15, Order of June 18, 2009, at 9). The Commission (at 2) further clarified that it uses "the term ECAM to refer to both an energy balancing account in general and the Company's proposed mechanism in particular." For the purposes of this phase, the first definition seems more relevant, since the PSC has deferred the details of any potential mechanism to the second phase.[1]

In its scoping order in this docket (June 18, 2009, at 9–10), the PSC elaborated that this phase should address, at a minimum, the following issues:

- an explicit and quantitative analysis of the risks of fluctuating power costs i.e., the magnitude and nature of the risks;
- whether these risks are manageable and by whom;
- who should bear the risks;
- what alternatives are available to manage these risks;
- evaluation of rate-making issues associated with power costs and the valid regulatory processes which will effectively handle such costs;
- evaluation of regulatory objectives and the ability of a ratemaking treatment of power costs to balance the objectives;
- an analysis of the impacts of alternative ratemaking treatments of power costs to management incentives for least cost risk adjusted planning, expansion and operation;
- alignment of Company and customer objectives.

Q: How did RMP respond to these directions from the PSC?

A: On August 17, 2009, RMP filed supplemental testimony of Bruce Williams, Greg Duvall, Karl McDermott, and Frank Graves.

[1] Whether any second phase would occur depends on the results of this first phase. "If we find the adoption of an ECAM is in the public interest, we would then consider the design of an ECAM" (Docket No. 09-035-15, Order of June 18, 2009, at 9).

Q: Does the RMP supplemental testimony demonstrate that an ECAM is needed and in the public interest?

A: No. While RMP's supplemental witnesses make a large number of assertions, they provide little substantive support for those assertions or for the Company's position that an ECAM is needed or in the public interest.

Q: Please summarize the positions advanced in RMP's supplemental testimony.

A: Most of RMP's assertions can be grouped into the following four basic themes:

- PacifiCorp's net power cost (NPC) has consistently been higher than the costs allowed in Utah rates for the same period.
- The NPC is subject to many volatile cost drivers that are beyond PacifiCorp's control.
- An ECAM would have benefits to customers, even beyond the reduction in risk to PacifiCorp shareholders.
- An ECAM would have no adverse incentive effect, as demonstrated by the widespread adoption of ECAM-like mechanisms.

Q: Please summarize your conclusions.

A: I conclude as follows:

- The Company has failed to provide the explicit and quantitative analysis of the magnitude and nature of the factors driving fluctuations in power costs required by the PSC.
- The Company grossly exaggerates the uncontrollable risks to which it is exposed by the lack of an appropriately-structured ECAM.
- The Company's claims that ECAM provides ratepayer benefits are incorrect.

- An ECAM would create incentive problems that would be very difficult to correct.
- The Company has not demonstrated that an ECAM is needed or that it would be in the public interest.

Q: Please summarize your recommendations.

A: I recommend that the PSC reject RMP's request for an ECAM.

Q: How is the rest of your testimony structured?

A: I examine RMP's application and testimony in view of the Commission's scope for this case, grouping the issues by the following topic areas:

- the Company's explanation of past differences between Utah-allowed and actual NPC;
- the scope of NPC risks to which RMP is exposed;
- customer benefits of an ECAM;
- the effect of an ECAM on PacifiCorp's incentives for cost control.

III. Historical Differences between Utah-Allowed and Actual Net Power Cost

Q: What evidence does the Company provide about the explicit and quantitative analysis of the magnitude and nature of the risks of fluctuating power costs, which the PSC required in the scoping order?

A: In his supplemental testimony (at 2), Mr. Duvall asserts that he and Dr. McDermott address this issue.

Q: How does Mr. Duvall address this issue?

A: His central piece of evidence is Table 1 (at 4; actually a graph), which Mr. Duvall says compares actual PacifiCorp NPC to the PacifiCorp-wide NPC authorized in Utah.

Mr. Duvall observes that the actual and authorized NPCs were quite close for 1990–1999, and that the deviations in 2000 and 2001 were due to the power crisis and the Hunter outage.[2] From 2002 through 2008, Mr. Duvall reports that "the amount of NPC included in the Company's rates consistently has been below its actual costs, in every year by a wide margin" (Duvall Supplemental at 5).

Q: How does Mr. Duvall explain the 2002–2008 results in Table 1?

A: Mr. Duvall asserts (at 5),

> The primary reasons are that the current mechanism of using normalized modeled NPC does not account for the increased uncertainty and volatility of assumptions that are key drivers to actual NPC. The difference between modeled authorized (normalized) NPC and actual NPC has become more pronounced in recent years due to both increased price volatility in natural gas and electricity prices and Rocky Mountain Power's increasing resource portfolio exposure to uncertainty and volatility. Rocky Mountain Power's portfolio mix of resources is highly diversified, but the mix of resources in the past several years has changed and is projected to continue to increase reliance on flexible natural gas resources and intermittent renewable wind resources. At the same time, potential carbon legislation also increases uncertainty on the cost of emissions from historically more stable coal generation resource costs.

Q: Do future increased reliance on gas and wind explain the differentials in Mr. Duvall's Table 1?

A: No.

Q: Does potential carbon legislation explain the differentials in Mr. Duvall's Table 1?

A: No.

[2]The effect of the power crisis on PacifiCorp was exacerbated by PacifiCorp's short power position at the time.

Q: Excluding these forward-looking observations, what causes are left in Mr. Duvall's explanation?

A: Mr. Duvall claims that the differentials are due to "increased uncertainty and volatility of assumptions that are key drivers to actual NPC." He then elaborates that the uncertainty and volatility is due to (1) increased price volatility in natural gas and electricity prices and (2) increased reliance on gas and wind.

Q: Does Mr. Duvall demonstrate that the differentials in his Table 1 for 2002–2008 resulted from increased volatility in natural gas and electricity prices or increased reliance on gas and wind?

A: No. He does not offer any breakdown of the historical differentials.

Q: Would it have been straightforward for RMP to test whether increased volatility in natural gas and electricity prices or increased reliance on gas and wind generation have created the differentials in Mr. Duvall's Table 1?

A: It should be. The Company could have compared its projected prices for natural gas, short-term electric purchases, and short-term electric sales in its NPC projection (as modified by the UPSC order or stipulation) in each rate case with the actual price RMP booked in each year for which the resulting rates were in effect. Multiplying the difference in price by the annual quantity would provide an approximation of the effect of changes in prices between the NPC forecast and actual values. Similarly, RMP could easily compare its projected and actual generation of wind power, and value the difference at some proxy price, such as average short-term sales by month and time period (HLH versus LLH). For wind power, the comparison would be between the price of the wind purchase and the costs of a proxy for replacement power.

The Company's failure to support its assertions regarding the origin of past differentials between projected and booked NPC undermine its arguments about the need for an ECAM.

A. Variability in Electric and Gas Prices

Q: Has RMP provided information about the variability of prices for gas and wholesale electricity?

A: Yes. Mr. Graves presents spot market prices for gas at Opal and electricity at Palo Verde in his Figure 4 (Graves Supplemental at 16).

Q: Does this information demonstrate that variability of prices for gas and wholesale electricity resulted in the variation between the projected and booked NPC values?

A: No, for at least three reasons. First, RMP has not demonstrated that the commodity price forecasts used in developing the NPCs for various years were incorrect. The data provided by the Company show that prices change over time, so that the spot price of gas in January 2008, for example, was higher than in January 2007. That does not imply that the spot price of gas in January 2008 was higher than the forecast of gas prices for January 2008 when the NPC projection was developed.

Second, even if the spot gas price (for example) were higher than the price forecast in PacifiCorp's NPC projection, that price difference would raise NPC compared to the forecast only if PacifiCorp were buying in the spot market. If PacifiCorp purchased the gas prior to developing its NPC projection, subsequent changes in forward prices (as well as differences between forward and spot prices) will have no effect on the cost of that quantity of gas. The Company acknowledges that fact (DR OCS 2.54).

Third, since PacifiCorp buys gas and electricity and sells electricity (and may also sell off previously-contracted gas it no longer needs), changes in prices cut both ways. An increase in gas and electric prices may increase PacifiCorp's costs for purchases, but increase its sales revenues by an equal or greater amount, especially since PacifiCorp is a net seller in the short-term and spot electric markets.

Q: If it turned out that historical differences between PacifiCorp's forecast and actual NPC have been driven in part by changes in gas and electric prices, would that justify an ECAM?

A: No. As Mr. Duvall says (Supplemental at 6), "Hedging instruments are generally available to mitigate the risk of uncertainty in the price of natural gas and wholesale power for a known net open position."[3] Electricity contracts are available "up to about four years forward," and gas up to five years (DR OCS 2.121, OCS 2.128). Mr. Graves describes PacifiCorp's hedging strategy, which largely insulates [redacted][4] Even were PacifiCorp exposed to gas and electric price risks in 2002–2008, it now appears to be substantially protected from price swings.

[redacted] (Confidential Attachment OCS

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[3]Mr. Duvall also says that "the Company was significantly hedged with regard to the forecast net open positions for power and natural gas at the time of several recent NPC filings" (Supplemental at 6), but does not define "significantly" or define how much of RMP's forecast net open positions were hedged in each year 2002–2008.

[4]Another witness for the Office, Lori Smith Schell, will address the hedging policies in more detail.

2.120) Mr. Graves describes these plans at some length. His conclusions are as follows:

> Conventional, financial hedges using forwards are available for two to four years or so, depending on the commodity involved and the location of delivery. (DR OCS 2.85)
>
> For those plants that can receive multiple sources of PRB and Utah coals, the Company has typically been able to get fixed prices for up to three years. (DR OCS 2.86b)

Natural gas is traded several years in advance at the Henry Hub.

The Company agrees that for coal, gas and power purchases and wholesale sales “the price would not be volatile if it is set at the time rates are determined and that price covers all the quantity that may be needed in the subsequent year” (DR OCS 2.45).

B. Load Uncertainty

Q: If gas and electric costs can be hedged, and have been significantly hedged in recent years, and will be mostly hedged in the future, what risk does RMP perceive with gas and electric price volatility?

A: Mr. Duvall implies that, even with some level of hedging, gas and electric price volatility was responsible for his observation that “actual NPC were substantially different than projected NPC” (Duvall Supplemental at 6). He presents no evidence to support that suggestion.

Mr. Duvall does offer an explanation how significantly-hedged gas and electric supplies can still contribute to a differential between projected and actual NPC. Mr. Duvall (Supplemental at 6) explains that, once the gas and electric positions are “significantly hedged,” then “significant variations subsequently occur in the net open position through the actual period as a result of the large, uncontrollable and unpredictable volatility in both loads and resources that occur simultaneously with large, uncontrollable and unpredictable volatility in prices of natural gas and electricity."

I interpret Mr. Duvall's explanation as a claim that, in each year, two types of events occurred simultaneously:

- PacifiCorp's load was higher than projected, or its resources were lower than expected, so PacifiCorp needed additional energy;
- Market prices for gas and electricity were higher than expected, so the additional energy was particularly expensive.[5]

Q: Does Mr. Duvall offer specific examples that demonstrate that those conditions occurred over any of the years from 2002 through 2008?

A: No. Mr. Duvall (Supplemental at 7) provides a partial example for one hour, January 27, 2009, which d not even within the 2002–2008 period of Table 1. He points out that load in that hour was higher than forecast two months earlier.[6]

Q: Does Mr. Duvall explain why that particular November forecast is particularly important?

A: No. The NPC portion of rates in effect for January 2009 would have been determined by the PSC decision in 07-035-93, issued August 11, 2008, and based on RMP updates through the hearing in June and the subsequent stipulation in September, 2008. Given the hedging policies described by Mr. Graves, it does not appear that PacifiCorp would have been purchasing much gas or making most of its electric commitments in November 2008 for January 2009.

[5]Other parts of Mr. Duvall's testimony (e.g. at 7, lines 148–149) suggest that low loads or high resource levels, combined with low market prices, might have an adverse effect, although he does not describe the underlying mechanism for that effect.

[6]Mr. Duvall also notes , "On February 7, 2009, actual loads were 524 MW below expectation," but does not explain when that expectation was established.

Q: What is the significance of a particular hour having a higher load than forecast two months earlier?

A: Not much. It seems obvious that any forecast of the loads on particular hours conducted more than a few days in advance will be wrong. In any January, there will be some very cold days and some mild ones; in any July, there will be some very hot days and some merely warm ones. Mr. Duvall does not provide any data on the accuracy of its load forecasting on an annual basis.

Q: If PacifiCorp has not been doing a good job of forecasting a realistic pattern of high and low loads for estimating NPC, would that justify implementing an ECAM?

A: No. In that case, PacifiCorp should improve its load modeling for NPC.

Q: Did Mr. Duvall demonstrate that electricity and gas were more expensive on January 27, 2009 than anticipated in November 2008?

A: No. He does not present any information on the projected and actual commodity prices.

Q: Do you have any of that information?

A: I have that information for natural gas. In November 2008, the price settlements for natural gas at Henry Hub for January 2009 ranged from $6.39 to $7.49/MMBtu, averaging $6.82/MMBtu over the 19 trading days in the month. In May and June 2008, when the NPC estimates were being finalized, the January forward averaged $13.13/MMBtu. Even earlier, back as far as January 2006, the forward contract for January 2009 traded in the $8–$12/MMBtu range. The Henry Hub spot price on January 26 for January 27 was

$4.62/MMBtu.[7] Nor was gas particularly expensive in the West; the spot price at Opal was $3.27/MMBtu.

Hence, if PacifiCorp's response to the high loads on January 27, 2009 was to run its gas plants more, the cost of the additional gas would be lower than was expected when the NPC was determined.

Q: What was RMP's estimate of the additional cost of the higher loads on January 27, 2009?

A: The Company was unable to estimate that cost (DR OCS-15b). Nor could the Company identify the cost effects of the lower loads on February 7, 2009 (DR OCS-15f).

Q: Were RMP's NPC greater than expected on January 27, 2009, would that be a problem for the Company?

A: No. First, as I discussed above, the NPC rate should be set to reflect some cold days in January; whether GRID happened to identify that January 27, 2009 was one of those days is irrelevant for setting annual rates. Second, RMP's revenues must also have been greater than expected for January 27, 2009, since additional load results from additional sales.

Q: What is RMP's estimate of the increase in its retail sales revenue over forecast due to the high loads on January 27, 2009?

A: The Company was unable to (or declined to) estimate those revenues (DR OCS-15d).

Q: Is it likely that RMP shareholders lost money due to the higher load on January 27, 2009?

[7] This is the average price for the day reported by the Intercontinental Exchange at www.theice.com.

A: No. Even if the incremental cost of gas and electric purchases and the revenue lost from foregone off-system sales per kWh of incremental load equalled or exceeded the NPC embedded in RMP's rates, its total revenues are set to cover many other cost components (fixed generation costs, transmission, distribution and general) that did not increase with the load on that day. Increased sales are almost always beneficial to utility shareholders.

Q: Has RMP estimated the effect of unexpected increases in annual sales on NPC and revenues?

A: No. The Company claims to be unable to estimate either of those values (DR OCA-2.55, 2.64). Thus, there is no evidence that short-term load uncertainty actually poses financial problems for RMP.

Q: Does RMP offer any other explanation for why it cannot fully hedge fuel and wholesale electric transactions?

A: Yes. Mr. Graves suggests that fuel and electric prices cannot be hedged for the following reasons:

- PacifiCorp does business at "remote locations where few buyers other than the local utility transact business" (Graves Supplemental at 34).
- "It is difficult to cover the complex (uneven, irregular, weather dependent) load shapes of retail load customers" (Supplemental at 35).
- The "duration of available hedges is fairly short" (Supplemental at 35), by which Mr. Graves appears to mean more than a few years into the future (DR OCS 2.121, 2.128).

Q: What is the importance of Mr. Graves's three points?

A: Not much, from the perspective of whether to implement an ECAM. His first point (remote locations) would be important if RMP's cost risks were being driven by the need to dispatch generation out of merit order to meet unexpected loads in isolated areas. The Company does not make that argument.

As to his second point, Mr. Graves is correct that PacifiCorp cannot hedge costs in every hour. Fortunately, that is not necessary for the NPC in rates to cover actual NPC. If rates are based on the costs of meeting load at a variety of load levels, and if PacifiCorp is hedged for bulk power supply (including sale of its excess wholesale energy), then the deviation of costs from the projection, over the course of a year, should be small, and the average deviation over many years should be smaller still.

Mr. Graves's third point is also technically correct, but irrelevant to the question of need for an ECAM. Unless the Commission wants to encourage RMP to file rate cases less frequently, existing hedges and contract horizons are adequate for ratemaking. If RMP's contracts indicate that its NPC will rise faster than revenues after the test year, the Company can choose to file a new rate case.

Q: Does Mr. Graves express other concerns with hedging and contracting?

A: Yes. He seems to be concerned in many places in his testimony that PacifiCorp will enter into contracts and later face price risks if it wishes to liquidate those contracts as market prices and volatility change. For example, Mr. Graves worries that "Market parameters change in unforeseen and unforeseeable ways, invalidating prior hedged positions" (Supplemental at 35).

This would be a valid concern for a power marketer, who makes money on buying and selling power in the markets. For RMP, which sells its retail power at prices set by the Commission, a change in the market price for gas, power, or coal it has already purchased will not normally be a problem. Indeed, in discovery, Mr. Graves backs off of his testimony, limiting his concern about "invalidating prior hedged positions" to a nebulous possibility that market price changes will "expose the utility to a credit risk or trigger a cash collateral event." (DR OCS 2.124) He also reverses his position that changes in market prices invalidate prior hedged positions; instead decrying their effect on *unhedged* positions:

> Changes in market parameters may also make the utility's unhedged positions more or less risky than before the change, thereby "invalidating" some of the overall portfolio hedging plan or its attainment from prior positions. (DR OCS 2.124)

In other words, changes in market prices may cause PacifiCorp to regret its failure to hedge supplies prior to the setting of NPC in the rate case but those price changes are unlikely to increase the costs of hedged supplies.

PacifiCorp may need to adjust its commodity commitments (although in the case of coal, it can also adjust its coal stocks) to reflect changes in load forecasts or resource availability. These adjustments should average out, unless there is some correlation among loads, availability, and prices, which RMP has not demonstrated.

C. Wind Generation

Q: Has RMP provided information about the differentials between forecasted and actual generation by the wind plants it owns or purchases from?

A: No.

Q: If RMP did provide information demonstrating that wind generation varies substantially between years, would that demonstrate the wind variation has or will contribute to variation in the NPC?

A: No. Reduced generation by a PacifiCorp-owned wind farm would reduce the energy available for off-system sales or increase PacifiCorp's need to purchase power or increase output at thermal (probably gas-fired) plants. Those changes would increase NPC. On the other hand, reduced generation by a wind farm selling to PacifiCorp would have similar effects on sales, purchases or fuel costs, but would reduce the amount that PacifiCorp pays the wind-farm owner. So long as the wind-power contract price is higher than the cost of the incremental fuel or purchase, or the lost sale, reduced wind generation will reduce NPC.

Q: Did RMP discuss all the causes of the historical variation between the Utah-authorized NPC and PacifiCorp booked NPC?

A: No. I have identified two additional factors that reduce the discrepancies, and even show that in some years in which Mr. Duvall reports that RMP under-collected NPC, the Company actually over-collected NPC.

First, the actual NPC values in Mr. Duvall's Table 1 are not adjusted for differences in sales from the forecast, nor for differences due to policy or prudence determinations. If sales are greater than forecast, NPC should be greater than forecast, but PacifiCorp revenues would be greater as well. That situation would not be problematic for PacifiCorp; if anything, earnings would likely be increased by the higher sales level.

The Company's forecast of NPC for 1992, which was reflected in rates in 1992 through early 1999, was $392 million and RMP reports that actual NPC was $445 million in 1998 (Duvall Supplemental Table 1 workpaper). Mr. Duvall therefore concludes that cost exceeded revenue by $53 million in 1998. From the EIA Form 861 data base, PacifiCorp retail sales were 41,511 GWh in 1992 and 46,884 GWh in 1998. Since rates remained the same while sales grew 13%, the NPC included in rates by 1998 would have been about $443 million. Hence, NPC-related revenues were within $2 million of the actual NPC in 1998, rather than $53 million below.

Second, RMP acknowledges that the Table 1 "actual data does not include a revenue imputation for SMUD" (DR OCS 2.9). In other words, Mr. Duvall did not adjust his Table 1 to Utah-regulatory terms.

D. Modeling of Potential Risks

Q: Which RMP witnesses attempt to quantify RMP's NPC risks?

A: Mr. Duvall (Duvall Supplemental at 8) and Dr. McDermott (McDermott Supplemental at 27–28, Tables 2 and 3) address this issue.

Q: What was Mr. Duvall's analysis?

A: Mr. Duvall attempted to estimate the contribution to expected NPC of random variation in loads, forced outages, and hydro generation. He compared 100 stochastic iterations for 2012 NPC using random values for these variables (along with fuel costs) with 100 runs with load, outage, and hydro generation fixed.

Q: Does Mr. Duvall's analysis support the need for an ECAM?

A: No. While I have not been able to review fully the assumptions and analysis, I have identified three issues with the analysis that undermine RMP's use of the results to support the need for an ECAM.

First, Mr. Duvall overstates the effects of load variability on RMP earnings. He estimates NPC for a range of load levels, but does not compute RMP revenues for each of the corresponding sales levels. The high-cost iterations tend to be the highest-sale iterations, and would have revenues (both for NPC and other cost components) as much as 25% greater than the forecast. Many of the high-cost, high-load iterations might actually be profitable to RMP. Mr. Duvall ignore the increased revenues in these cases.

Second, the load variability in this analysis is quite extreme. The annual energy requirements in the 100 stochastic iterations range from 18% below expectation to 25% above (Attachment OCS 2.21). Thirteen of the 100 runs have loads at least 10% greater than forecast. Since the ECAM is intended to cover changes in NPC only between rate cases, and since RMP would have the opportunity to file a rate case if loads (and hence costs for generation, transmission and distribution) were rising rapidly, the chance of annual energy requirements being even 10% above forecast over a year or two must be much lower than 13%.[8] Perhaps Mr. Duvall was modeling the uncertainty in 2012 energy requirements at the time of the 2008 IRP, rather than at a later time when rates for 2012 would be set.

Third, and most fundamentally, Mr. Duvall's analysis supports a critique of PacifiCorp's NPC forecasting as well or better than a critique of Utah's regulation. He points out that ignoring variability in hydro output, forced outages, and loads results in an underestimate of expected NPC. If PacifiCorp's forecast of NPC ignores variability and is therefore consistently understated, the solution is to improve that forecast, rather than eliminate RMP's incentives to control costs. I understand that the GRID model reflects stochastic forced outages, as do all complex production costing models, and models a range of hydro conditions. If uncertainty in loads has an important effect on RMP's annual NPC, RMP should be working to incorporate that uncertainty in its forecasting (although not with

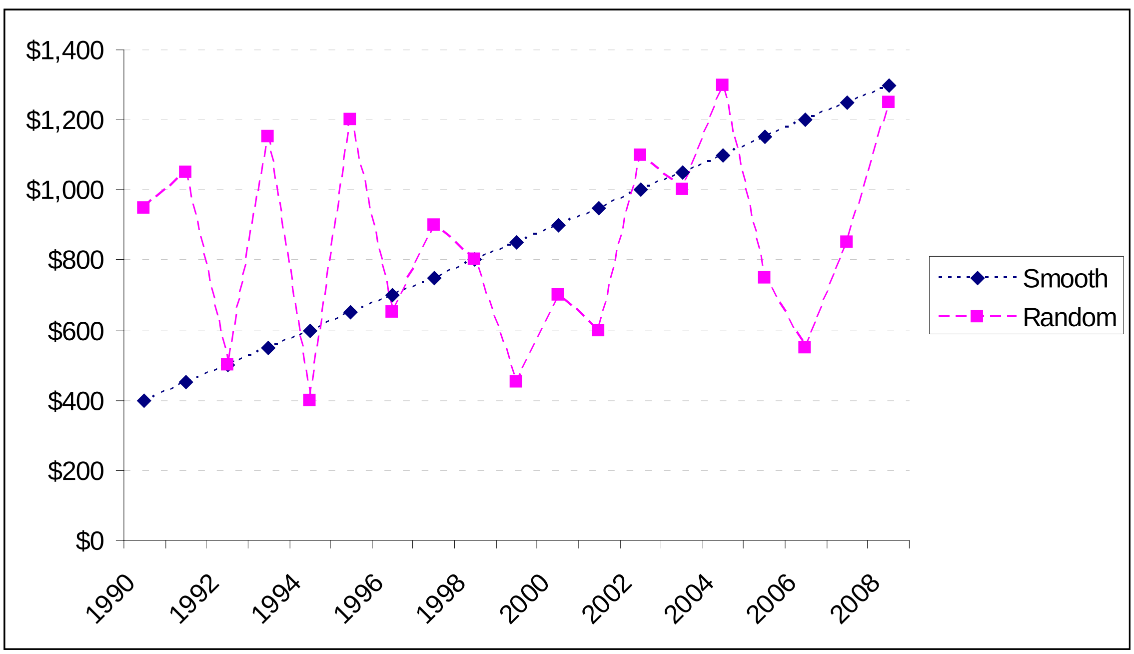
[8]The Company would generally know in advance of major drivers of load, such as new industrial, commercial, or residential development.

the extraordinary swings in energy requirements assumed in Mr. Duvall's model).

Q: Is Dr. McDermott's analysis of the coefficient of variation for expenses any more relevant to the issue of the need for an ECAM?

A: No. First, the coefficient of variation simply measures the dispersion among the annual values in the sample; it does not measure the volatility from one year to the next. Dr. McDermott is confused about this point, claiming that standard deviation is the same as the variation from year to year (DR OCS 2.51). The two patterns of costs in Figure 1 below have the same mean, standard deviation and coefficient of variation, but those costs occur in different patterns over time, resulting in very different year-to-year variation and volatility.[9]

Figure 1: Smooth and Volatile Cost Patterns



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[9]Each pattern in Figure 1 comprises the same data set of annual values, arranged in different chronological order.

Second, some of the "volatility" in Dr. McDermott analysis simply reflects inflation from 1992 to 2008.

Third, Dr. McDermott uses expenses in each category, rather than costs per MWh; some of the increase in expenses was offset by increased revenues from load growth, which Dr. McDermott effectively ignores. I discuss this in more detail in association with Mr. Duvall's Table 1 (at the start of Section III above).

Fourth, and most important, Dr. McDermott does not reflect the rate increases that the Utah PSC allowed in this period. Even had those rate increases covered NPC in every year, Dr. McDermott's analysis would still have identified the same level of volatility and risk for RMP.

IV. Not All Risks Are Relevant to Energy-Cost-Adjustment Mechanisms

Q: Other than gas and electric market prices and the possible correlation with loads and generation availability, does RMP discuss the nature and magnitude of other risks that may drive fluctuating power costs?

A: Yes. While RMP acknowledges that "Natural gas purchases and power purchases are the main examples of highly uncertain variable operating costs" (DR OCS 2.103), Company witnesses also mention the following sources of risk:

- potential carbon legislation (Duvall Supplemental at 5, 11; Graves Supplemental at 5, 19);
- the price of coal from non-captive mines (Duvall Supplemental at 10–11);
- spot market prices for coal (McDermott Supplemental 25);
- the quantity of coal used, even from captive mines, because the quantity is "related to demand that is not under the control of the utility" (McDermott Supplemental at 30);

- variability in hydro generation (Duvall Supplemental at 7–8, Graves Supplemental at 17);
- the resource mix of available generation changes over time as assets are built or retired (Graves Supplemental at 17);
- environmental surcharges for SO_2 (Graves Supplemental at 19);
- transmission wheeling charges, (Graves Supplemental at 20);
- fuel transportation charges (Graves Supplemental at 20);
- holding excess allowances whose value may increase or decrease (Graves Supplemental at 20);
- default by counterparties (Graves Supplemental at 38–39);

Q: Does the prospect of climate legislation justify implementation of an ECAM?

A: No. Under the proposed legislation, utilities will be allocated allowances for a significant portion of their historical carbon emissions, and additional allowances will be available for purchase at auction prior to the compliance date. Experience with other emissions trading schemes (for CO_2 in Europe and the Northeast, and for NOx and SO_2 regionally and nationally) indicates that once the legislation is enacted forward contracts will start trading. This will provide RMP with additional options for covering its obligations.

In the unlikely event that RMP finds itself in a rate case immediately prior to implementation of carbon legislation, facing undefined rules and a rudimentary market, it should propose a ratemaking solution to fit the conditions of that specific circumstance.

Q: Is the price of coal from non-captive mines or the spot price of coal a significant risk factor for RMP's NPC on the time scale over which an ECAM would operate?

A: No. PacifiCorp receives more than 30% of its coal from captive mines (Duvall Supplemental at 10), and purchases 99.4% of the remainder under long-term contracts with an average remaining duration of 3.4 years (Attachment OCS 2.27). The bulk of PacifiCorp's coal supply is thus locked in for the typical period between rate cases.

Q: How relevant are the spot coal prices in Dr. McDermott's Figure 4 to the need for an ECAM in Utah?

A: They are not very relevant. As noted above, PacifiCorp purchases very little of its coal in the spot market. Dr. McDermott does not provide any data on contract coal prices.

In addition, of the five coal regions for which Dr. McDermott's Figure 4 reports prices, PacifiCorp purchases only from the two least-expensive and least-volatile regions: 24% of its supply comes from the Powder River Basin and 35% from the Uinta Basin.

Q: Is the quantity of coal used by PacifiCorp "related to demand that is not under the control of the utility," as Dr. McDermott asserts?

A: That is not RMP's position elsewhere in discovery, where the Company asserts that coal-plant dispatch is not dependent on PacifiCorp load (DR OCS-2.16). The latter position is probably correct on this point, given the low running cost of the coal plants.

Q: If the quantity of coal used by PacifiCorp were "related to demand that is not under the control of the utility," as Dr. McDermott asserts, would that be a problem for PacifiCorp?

A: No. Since PacifiCorp's retail rates exceed the cost of coal, higher demand met by burning additional coal would benefit PacifiCorp. Dr. McDermott argues that a demand-related increase in coal use "may be an issue for PacifiCorp" and justifies ignoring the associated revenues by saying that he "is not referring to revenue in this portion of his testimony" (DR OCS 2.61).

Q: To what extent is variability in PacifiCorp's hydro generation relevant to Utah?

A: The variability is not very relevant. The Revised Protocol is designed to take away from Utah most of the benefits of PacifiCorp hydro entitlement. If Utah gets no benefit from PacifiCorp's major hydro resources in the allocation of forecasted NPC, Utah should not be charged for the increased cost if hydro generation is below the level expected in the rate-case NPC.

The Company does not seem to understand this relationship, and suggests, "All of the hydro variability would flow through to Utah" (DR OCS 2.20).

Q: Is the change in generation-resource mix as assets are built or retired a source of risk that might be addressed by an ECAM?

A: No. The effects of additions and retirements can be forecast in the rate case before the change in supply.[10]

Q: Are environmental surcharges for SO_2 a significant source of risk for PacifiCorp?

A: No. PacifiCorp is a net seller of SO_2 allowances (DR OCS 2.98) and can retain excess SO_2 allowances well in advance of usage.

Q: Would holding excess allowances whose value may increase or decrease expose PacifiCorp to risk?

[10] On occasion, delay in completing a generator may temporarily increase NPC. On the other hand, if PacifiCorp can bring a plant on line ahead of schedule, NPC will decrease. The completion of resources is at least in part under PacifiCorp's control.

A: No. PacifiCorp's NPC includes allowances and other commodities at cost, not at market value. If PacifiCorp has unexpected excess allowances due to reduced coal generation, it can use or sell those allowances in later years.

As in several places in his testimony and discovery responses, Mr. Graves's comments on the risks of holding excess allowances conflates PacifiCorp's recovery of costs through the NPC with a power-trading firm's revenues from market transactions. If PacifiCorp purchases a commodity hedge, or a forward contract for delivery to PacifiCorp, and prices fall, PacifiCorp has no need to unwind that position. PacifiCorp revenues are based on expectations, including committed hedges, at the time of the rate case. The power trader, on the other hand, would need to sell that same hedged supply at a loss.

Q: Do transmission wheeling charges expose PacifiCorp to NPC risk?

A: Not much. Transmission rates are regulated and not subject to wide swings. PacifiCorp can take wheeling charges into account in deciding whether to procure remote resources.

Asked to demonstrate that transmission wheeling charges are uncertain in price and required volume, RMP provided only the datum that wheeling expense changed by $12 million from the prior general rate case to the current general rate case, reflecting changes in both price and volume (DR OCS 2.99b). Changes known in a rate case are not uncertainties that would justify an ECAM. With the addition of new wind resources, PacifiCorp may be incurring predicted new wheeling charges as part of the resource addition.

Q: Do fuel transportation charges expose PacifiCorp to NPC risk?

A: Transportation charges are a part of the delivered cost of coal and gas. As RMP notes, pipeline tariffs are regulated (DR OCS 2.99) In any case, RMP did not provide any evidence of material risk from fuel transportation charges. (Ibid.)

Q: Does default by counterparties expose PacifiCorp to significant risk?

A: No. The Company was only able to identify two occasions since 2000 on which PacifiCorp suppliers went into default: Enron and Lehman Brothers (DR OCS 2.135). In neither case did PacifiCorp experience any loss.

V. Alleged Customer Benefits of an Energy-Cost-Adjustment Mechanism

Q: What customer benefits does RMP allege would flow from an ECAM?

A: I count four such benefits claimed in RMP's supplemental testimony, as follows:

- increased efficiency due to better price signals to customers;
- stability and gradualism in rates;
- avoiding situations in which the financial stress of high, unrecoverable NPC encourages management to skimp on maintenance and investment, resulting in degraded reliability;
- lower costs of capital.

A. Increased Pricing Efficiency

Q: Which RMP witnesses promise that an ECAM would result in increased efficiency?

A: Dr. McDermott asserts that "we should expect that consumers will be better off under an ECAM approach" (Supplemental at 13) because

> 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. (Supplemental at 15)

Mr. Graves says, "Timely recovery of NPC will help customers receive accurate information about the economic value of power, in order to make efficient consumption decisions. This may seem like cold comfort, but in fact it can be very valuable" (Supplemental at 6).

Q: Is this claim valid?

A: Dr. McDermott's statement from page 15 (quoted above) is correct, but an ECAM would not result in efficient pricing. Dr. McDermott's description of the benefits of setting prices at the cost of production is rather an argument for marginal-cost pricing, including time-of-use and real-time pricing, in which the rate faced by the customer in each hour reflects the cost in that hour. That is principally a issue of rate design.

An ECAM would not increase rates in the hour, day, or even month in which costs are high; it would defer the difference between forecast and actual NPC in one period (a year in RMP's proposal, but potentially some shorter period, such as a quarter) for collection in a later period. Assuming that NPC is accurately forecast for the second period, the ECAM would make rates too high in that period, again sending the wrong price signal.

As Mr. Graves concedes, "For certain decisions,...[efficient pricing] requires a very short, very immediate horizon of price revelation, such as 5-minute locational marginal prices (LMPs) needed to induce peak-demand shifting. For other, longer term decisions, such as replacing appliances with more efficient new ones, a price indicative of the expected long run marginal cost is more relevant, which need not be signaled or updated extremely frequently to be useful to customers' decisions." (DR OCS 2.116b) Increased volatility in NPC prices, with the lags inherent in any ECAM, would not improve pricing signals for peak shifting or for appliance efficiency.

Q: Does RMP recognize that efficient price signals require marginal-cost-based rates?

A: Interestingly, the RMP witnesses are split on this point. On the one hand, "Dr. McDermott claims that economic theory suggests that prices that more closely reflect cost (either average or marginal cost) result in better price signals" (DR OCS 2.42). I know of no economic theory that would suggest that average-cost pricing is efficient. He also emphasizes that consumers make decisions about incremental (i.e., marginal) prices and benefits of energy usage (Supplemental at 15).

In contrast, Mr. Graves correctly states that "Efficient prices signal the avoidable, marginal cost of consumption to customers" (DR OCS 2.116b).

Q: Does RMP demonstrate that an ECAM in the period 2002–2008 would have better matched prices to cost?

A: No. On the contrary, Dr. McDermott admits that an ECAM that recovered NPC shortfalls from 2001 or 2004 in the following year would not have resulted in rates "closer to production costs than was actually the case without an ECAM" (DR OCS 2.42b and 2.42c).

Q: Does Dr. McDermott cite any other regulators to support his argument regarding the efficiency of pricing with an ECAM?

A: Yes, but inaccurately. Dr. McDermott quotes the Minnesota PUC to the effect that an ECAM matches power expenses and rates (which is certainly the case over time), as evidence that the Minnesota PUC identified "directing consumers to consume only that incremental amount of electricity that provides them an equal incremental benefit" as a benefit of ECAMs (Supplemental 15). The quote from the Minnesota PUC as reproduced by Dr. McDermott and in context appears to refer to matching utility costs and revenues, without any reference to consumer response. Dr. McDermott was unable to explain how that Minnesota PUC order had any connection to his point.[11]

Q: What schedule for ECAM filings does RMP propose?

A: Mr. Duvall proposes an annual filing on December 15, with the ECAM adjustment effective February 15 (Duvall Direct testimony at 8–9). The Company reiterated that position in DR OCS 2.29 and DR OCS 2.104.

Q: What schedule for ECAM filings does Mr. Graves assume in his testimony?

A: He believes that to be an issue for Phase 2, so he cannot determine how an ECAM would have affected prices over 1990–2008. (DR OCS 2.92). He also acknowledges,

> The efficiency advantages of an ECAM, as well as the financial risk-reduction benefits, are greater with a shorter horizon for passing through the actual costs. At present, at least an annual accrual and amortization pattern has been suggested but this is not a finalized aspect of the ECAM policy. (DR OCS 2.116a)

B. Gradualism

Q: Which RMP witness argues that an ECAM would promote gradualism in ratemaking?

A: Mr. Graves says,

> Eventually, customers should bear all of the costs that are prudently incurred to provide service. If this is done in a timely, incremental fashion, customers do not experience occasional, jarring rate shocks, and they have the ability to make gradual adjustments to their own consumption habits. (Supplemental at 6)

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[11]The order he cited was not considering whether to implement or continue an ECAM, but whether to change the allocation of ECAM charges among rate classes. The issue appeared to be inter-class equity, rather than efficiency.

> With an ECAM, the costs will be recognized and passed on in a more gradual, smoother way that avoids disruptive rate shocks. (Supplemental at 11)

Q: Would an ECAM result in more gradual changes in rates than the PSC's current approach?

A: Not in any systematic way. In general, an ECAM would tend to delay a price spike in year 1 to the subsequent year 2, when prices may still be high, resulting in collecting year-2 and the excess year-1 costs in year 2, producing a greater price jump from year 1 to year 2.

Mr. Graves was unable to demonstrate any gradualism benefit for RMP's historical NPC data (DR OCS 2.92) He describes the "gradualism" benefit of an ECAM as follows: "An ECAM is more likely to routinely adjust rates up and down, in response to recent market conditions, than a test-year, base-rates mechanism" (DR OCS 2.115a). This description of ECAM operation implies greater volatility in rates, not gradualism.

An ECAM would be unlikely to provide either gradualism in adjustment of rates or strong contemporaneous signals of changing prices. It would be very unlikely to provide both gradualism (which requires slow price changes) and strong price signals (which often require rapid price changes).

C. Skimping on Maintenance and Investment

Q: Where does RMP argue the that lack of an ECAM would cause management to skimp on maintenance and investment, resulting in degraded reliability and have adverse long-term impacts on customers?

A: Dr. McDermott asserts that, if fuel costs exceed the level of costs in rates,

> 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. (Supplemental at11)

> 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. (Supplemental at 15)

So does Mr. Graves:

> If costs prove to be higher than forecast, the utility attempts to live within the operating budget implied by that forecast for as long as possible. This can lead to stresses on the utility that are absorbed through such practices as reduced or deferred maintenance [or] underinvestment in otherwise attractive new infrastructure.... (Graves Supplemental at 7)

And RMP speaks for itself when it says,

> In the Company's view, rational business entities attempt to live within their operating budgets. If specific costs prove to be higher than the budgeted levels, entities take reasonable steps to compensate, including but not limited to reprioritizing and reducing other costs. (DR OCS 2.83)

Q: Has RMP identified any occasions on which PacifiCorp or any other utility has made such cuts?

A: No. Dr. McDermott cannot identify any "instances in which PacifiCorp has made budget cuts that increased long-term costs to customers, due to NPC variation" (DR OCS-2.35b) or "outages or slower restoration times" (DR OCS-2.41). Nor could he identify any other electric utility as having made budget cuts that increased long-term costs to customers (DR OCS 2.35c, 2.39, 2.40, 2.41b).[12]

The closest Dr. McDermott gets to an example of the problems he imagines might result from the lack of an ECAM is to cite the effect of the California power crisis on Southern California Edison and Pacific Gas and Electric. At that time, those utilities were purchasing entirely in the short-term market and were unable to raise rates to reflect market prices that were rising rapidly in response to Enron's manipulation of the wholesale market (DR, 2.39, 2.40). Even in that situation, which was much more severe than any NPC-induced crisis conceivable for RMP, given its resource mix and hedging, Dr. McDermott finds no evidence of damaging budget cuts.

Asked for occasions on which RMP or PacifiCorp has acted in the manner described by Mr. Graves, the Company cites a press release it issued following the decision in the 2008 rate case, in which it threatened to reduce customer service and even curtail power supply to customers. However, RMP is unable to estimate any costs to customers (DR OCS 2.83).

On the other hand, RMP also says that it has no budget limits for NPC. "The Company has an obligation to serve customer loads and does so at the lowest cost that can reasonably be achieved" (DR OCS 2.112).

Q: Does Dr. McDermott demonstrate that PacifiCorp or other utilities could make such cuts and evade facing penalties from regulators?

[12]Dr. McDermott explains his lack of empirical evidence for these problems by asserting that "there are few utilities without an ECAM" (DR OCS 2.39 and 2.40). Yet his testimony lists several jurisdictions and utilities that have recently adopted an ECAM (Supplemental at 36–37), so some examples should be available over the last few decades, if lack of an ECAM really causes utilities to cut back on other essential services.

A: No. He declines to provide any evidence that RMP or other utilities can profit from reducing service or reliability, and suggests that high actual NPC might instead result in lower profits to shareholders. When asked

> Is it Dr. McDermott's testimony that a utility can make budget cuts in ways that increase long-term costs to customers, without regulators identifying those costs and requiring shareholders to absorb them?

he responded as follows:

> This is not the point of Dr. McDermott's testimony. The point of the testimony is that denying a reasonable opportunity to recover legitimate costs can force a utility into a situation where it either cuts the return to shareholders or makes cuts in budgets that may harm customers. This situation is not fair to either customers or shareholders. Dr. McDermott did not testify as to whether he thinks regulators will "catch" a utility in such a situation as that is not the overriding purpose of regulation. The purpose of regulation is to create a set of incentives that, on balance, create an environment in which we expect utilities and customers to honor their respective parts of the regulatory bargain. (DR OCS 2.35d)[13]

D. Cost of Capital

Q: Would an ECAM reduce RMP's cost of capital?

A: Yes. In the event that the Commission institutes an ECAM, it should reduce RMP's authorized return, as did the Vermont Public Service Board in its recent approvals of stipulations to establish temporary ECAMs for two utilities.

VI. Incentive effects

Q: Please describe how RMP responds to the PSC's issues regarding the following incentives effects of an ECAM:

[13] While he does not say so, low actual NPC would result in higher profits to shareholders, so unbiased forecasts of NPC should result in average returns close to the authorized value.

- **evaluation of regulatory objectives and the ability of a ratemaking treatment of power costs to balance the objectives;**
- **an analysis of the impacts of alternative ratemaking treatments of power costs to management incentives for least cost risk adjusted planning, expansion, and operation;**
- **alignment of Company and customer objectives.**

A: The Company addresses these issues through the testimony of Dr. McDermott.

Q: What are RMP's principal arguments regarding the incentive effects of an ECAM?

A: The Company makes the following assertions:

- The Company has not seen any "direct evidence" of an incentive effect (McDermott Supplemental at 38).
- PacifiCorp has no control over NPC, so no incentive effect is possible.
- Even with an ECAM, NPC costs would be subject to regulatory review.
- If any such incentive effects exist, ECAM-like mechanisms would not be so widely accepted by regulators.

Dr. McDermott asserts that "nuanced understanding" of the "details of procurement incentives inherent in the current system…can be difficult to convey in a litigated proceeding" (Supplemental at 38). Dr. McDermott does not even try to convey that "nuanced understanding" or any explanation of why RMP's cost-control incentives would not change with an ECAM.

A. Evidence of an Incentive Effect

Q: Do RMP's witnesses describe any studies that examine the incentive effects of ECAM-like mechanisms or of power-cost recovery in general?

A: No. Dr. McDermott has not conducted any such analysis (DR OCS 2.74).

Q: Have you identified any such studies?

A: Yes. A number of studies have examined the effect of instituting ECAM-like mechanisms, or the transition from cost-of-service regulation (with ECAM-like mechanisms) to competitive power markets and/or incentive regulation. In all the examples I found, the researchers found that putting some or all of responsibility of fuel costs on the power-plant operator improved performance.

Kahn (1989, at 48, original emphasis) finds,

> The regulatory lag—the inevitable delay that regulation imposes in the downward adjustment of rate levels that produce excessive rates of return and in the upward adjustments ordinarily called for if profits are too low—is thus to be regarded not as a deplorable imperfection of regulation but as a positive advantage. Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[14]

Gollop and Karlson (1978, at 574–575) say that an ECAM

> can lead to higher total cost without introducing any [bias in technology choice]. Since the automatic adjustment policy is intended to circumvent the lag in the regulatory review process, a factor-neutral inefficiency…can result. In short, firms face reduced financial punishment if inefficient production methods are adopted….regulatory lag and formal hearings play an important efficiency inducing role. A policy designed to circumvent the regulatory process reduces the penalty for inefficient behavior. The fuel adjustment mechanism is just such a policy. Automatic rate increases immediately compensate for higher production costs. Our research suggests that [fuel] inefficiency results soon after fuel clauses are sufficiently liberalized. We first observe [fuel] inefficiency in 1971, the very year fuel clauses are widely introduced and have their customer coverage greatly extended.[15]

[14]Kahn, Alfred. 1989. *The Economics of Regulation: Principles and Institutions* Vol. II, 2nd Ed. Cambridge, Mass.: MIT Press.

[15]Gollop, Frank, and Stephen Karlson. 1978. "The Impact of the Fuel Adjustment Mechanism on Economic Efficiency" *Review of Economics and Statistics* 60(4) (Nov., 1978): 574-584

Bushwell and Wolfram (2005, at abstract page) state,

> Our results suggest that fuel efficiency improved by about 2% following divestitures, although nondivested plants that were subject to incentive regulation also saw fuel efficiency improvements of similar magnitudes. Our results suggest that changes in incentives were the main driver behind the efficiency improvements and that the ownership transfers had little positive and possibly negative impacts on fuel efficiency.[16]

According to Knittel (2002, at 530),

> those programs that modify traditional fuel cost passthrough programs such that the firm is held accountable for a portion of fuel cost overruns, and at the same time is able to capture some of the rents from cost savings, are associated with higher efficiency levels relative to the more traditional fuel cost programs.[17]

Fabrizio, Rose, and Wolfram (2006, at 1272) find,

> IOU plants in restructuring regimes reduced their labor and nonfuel operating expenses by 3 to 5 percent in anticipation of increased competition in electricity generation, relative to IOU plants in states that did not restructure their markets. The estimated efficiency gains are even larger when compared to a benchmark based on municipal, federal, and cooperative plants: on the order of 6 percent reductions in labor use and 12 percent reductions in nonfuel operating expenses relative to non-IOU plants over the same time period.[18]

Golec (1990, at 165) says,

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[16]Bushnell, James and Catherine Wolfram (2005). “Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants” CSEM WP-140. Berkeley, Cal.: University of California Energy Institute, Center for the Study of Energy Markets.

[17]Knittel, Christopher. 2002. “Alternative Regulatory Methods and Firm Efficiency: Stochastic Frontier Evidence from the US Electricity Industry” *Review of Economics and Statistics*, 84(3): 530–540.

[18]Fabrizio, Kira, Nancy Rose, and Catherine Wolfram. 2006. “Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency” *American Economic Review* 97(4): 1250–1277.

> It has become clear to PUCs that FACs have eliminated or lessened utility incentives to reduce fuel costs....[19]

Lien and Lihong (1996) note,

> for several years, the FAC has been the object of numerous criticisms, For one, they reduce the incentive to search for the least cost source of fuel. Baron and De Bondt (1979) and Kaserman and Tepel (1982) find some support for this….This second criticism of the FAC is perhaps its most basic; it distorts the incentive to produce efficiently. Tiemann (1978), Baron and De Bondt (1979, 1981), Atkinson and Halversen (1980), and Scott (1985) find that under certain conditions the FAC may induce the utility to bias its selection of inputs towards those whose costs are covered by the FAC pass-through. Gollop and Karlson (1978) provide empirical support for this possibility. For generation of electricity, typically, fuel is overutilized relative to capital inputs, resulting in plants operating at less than optimal heat rates.... A third elemental criticism is that the FAC can exacerbate problems associated with self dealing. (158)
>
> ...without FACs, the firm will naturally seek the cheapest source of fuel. (171)[20]

Isaacs (1982, at 168) concludes,

> Suspicions that fuel adjustment mechanisms distort input choices are justified. In the case of no fuel cost uncertainty, there is an incentive for utilities to invest in relatively more fuel-intensive technologies than would be employed by a firm producing the same output. The addition of uncertainty does not eradicate the result that input incentives are altered, but the interpretation of these biases as "profuel" or "antifuel" becomes difficult.[21]

Atkinson and Halvorsen (1982, at 82–83, 86) find that

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[19]Golec, Joseph. 1990. "The Financial Effects of Fuel Adjustment Clauses on Electric Utilities" *The Journal of Business* 63(2) (Apr., 1990): 165–186.

[20]Lien, Donald, and Lihong Liu. 1996. "Futures Trading and Fuel Adjustment Clauses" *Journal of Regulatory Economics* 9(2) (March 1996): 157–178.

[21]Isaacs, Mark. "Fuel Cost Adjustment Mechanisms and the Regulated Utility Facing Uncertain Fuel Prices" *The Bell Journal of Economics,* 13(1) (Spring 1982): 158–169.

> When a fuel adjustment clause is used….more than the cost minimizing amount of fuel will be used relative to capital and labor, respectively.... [F]uel adjustment clauses have a significant effect on input choice....[22]

The Regulatory Assistance Project (1994, at 4) says,

> It is not possible to discuss PBRs without briefly touching on the other extreme—the fuel adjustment clause. Most utilities have fuel adjustment clauses which, for the most part, allow utilities to recover every dollar they spend on fuel and some forms of purchased power. Fuel clauses, particularly the simpler versions, leave the utility with no incentive to control fuel costs.
>
> At the same time, they tilt the playing field in favor of high fuel cost options Fuel clauses also create a disincentive to the utility to operate its units efficiently. If a utility spends money to improve the fuel efficiency of a generator, the money spent on improvements decreases profits, while the savings (the lower fuel costs) are passed through to ratepayers under the fuel clause. Fuel clauses tell utilities that investments that save fuel are not a good expenditure.
>
> There are two potential solutions. The easiest and best is to recover fuel costs in the same manner as all other costs. If this is not feasible, the other option is to sever the link between actual fuel expenses and allowed revenues as fully as possible. Options here include adjusting only for changes in the price of fuel, but not in the generating mix or allowing recovery of only a portion of the variance between expected and actual fuel expense.[23]

Bonbright, Danielsen, and Kamershen (1988, at 574) say that "automatic clauses" (such as ECAM) are the subject of regulatory concern about several issues, including the tendency of such mechanisms to

[22] Atkinson, Scott and Robert Halvorsen. 1980. "A Test of Relative and Absolute Price Efficiency in Regulated Utilities" *Review of Economics and Statistics* 62(1) (Feb., 1980): 81–88.

[23] "Fuel Clauses—The Anti-PBR," sidebar in "Performance Based Regulation: A Policy Option for a Changing World." The Regulatory Assistance Project IssuesLetter (1994): 4.

> blunt a utility's incentive to minimize fuel costs, although a company stands to lose the time value of its money due to time lag before recovery and they are sometimes requires to use reasonable care in negotiations....[24]

Q: Are these results consistent with standard economic thought and practical experience?

A: Yes. Economics generally assumes that individuals and firms respond to financial incentives. Empirical studies generally confirm that economic actors engage less in an activity as its cost to them rises and do more as the reward increases.

Q: Does RMP assume in other parts of its testimony that financial incentives affect behavior?

A: Yes. Dr. McDermott assumes that consumers will respond to the pricing of electricity and have responded to prices of natural gas and petroleum (Supplemental at 15–16). He also asserts that financial incentives for power plant performance could produce "unintended consequences, such as promoting one resource over another" (Supplemental at 46), bias the "trade-off between energy efficiency and power production and purchase and the relative structure of the rewards with respect to fuel type which may cause a utility to desire to procure too much of one fuel type over another," and "impact…worker and customer safety" (DR OCS 2.80).

When asked to reconcile his position allowing full NPC pass-through to consumers would have no effect on utility incentives but that any modification of that pass-through could have very serious effects on utility incentives, Dr.

[24]Bonbright, James, Albert Danielsen, and David Kamerschen, 1988. *Principles of Public Utility Rates*. Arlington, Va.: Public Utility Reports. The authors cite Phillips (Charles Phillps Jr. 1984. The Regulation of Public Utilities: Theory and Practice. Arlington, Va.: Public Utility Report) at 236–237 for this analysis.

McDermott replied "The statements are made in different contexts and need not be reconciled" (DR OCS 2.81).

Q: What should the PSC conclude about the incentive effect of an ECAM?

A: The PSC should assume that an ECAM would reduce PacifiCorp's incentive to control costs by reducing attention to the least-cost procurement of gas and electric power, the marketing of wholesale power, and maintaining and improving the fuel efficiency and reliability of generation.

B. Utility Ability to Affect NPC

Q: Which RMP witnesses argue that PacifiCorp cannot affect the NPC?

A: Dr. McDermott argues strenuously that PacifiCorp's Net Power Cost is "largely beyond the control of utility management" (McDermott Supplemental at 30):

> the prices paid for fuel and power are not within the control of the utility.... (Supplemental at 39)

> 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. (Supplemental at 30)

> 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. (Supplemental at 31)

> 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. (McDermott Supplemental at 39)

> Dr. McDermott is of the opinion that PacifiCorp must pay a market-determined price for power that it procures and therefore has de minimis control over the price it pays for power. PacifiCorp can slightly alter the choice of which types of forward contracts it uses (e.g., the length of forward commitment), which will affect the available price, but it cannot negotiate for a better price on any standard product it uses. (DR OCS 2.46d)

> Dr. McDermott is of the opinion that PacifiCorp has de minimis control over the price it obtains for selling power as that power is sold in a market. (DR OCS 2.46g)

Q: Is it true that PacifiCorp has no control over its NPC?

A: No. PacifiCorp affects the NPC with the following decisions and actions:

- every generation and transmission maintenance decision it makes or neglects;
- the scheduling of every maintenance outage;
- selection and training of every employee whose activities may affect a generation unit, major transmission line or wholesale transaction;
- negotiation of each wholesale power purchase or sale;
- every wholesale power purchase or sale the Company does not consummate;
- each potential natural gas purchase that PacifiCorp accepts or rejects;
- every call that a PacifiCorp trader takes from or places to a market participant and the decisions not to make some calls;
- each decision to dispatch a generator;
- each forecast of load underlying purchase, sale and dispatch decisions.

Q: Does the Company recognize that PacifiCorp has some control over its NPC?

A: Yes. Dr. McDermott contradicts his basic position a couple pages later (at 40), when he admits that utilities have been found to have increased costs through their imprudence in "numerous examples." He also agrees (DR OCS 2.33) that PacifiCorp management has some degree of control over each of the following aspects of NPC:

- which short-term wholesale purchases and sales PacifiCorp makes;
- the quality of PacifiCorp negotiations of standard and non-standard short-term wholesale power contracts with third parties;
- the maintenance of generators, to the extent that affects outage rates and heat rates;
- the management of scheduled and forced outages, including spending on overtime and expedited delivery of equipment, to the extent those decisions affect the length of outages;
- the timing of maintenance outages;
- the purchase of fuel, including timing, contract periods and terms;
- the resale of fuel contracts that are excess to PacifiCorp's needs, given actual loads and operating conditions.[25]

Q: Dr. McDermott says (McDermott Supplemental at 39), "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." Is he correct?

A: Not for PacifiCorp. Dr. McDermott's description might be accurate for some utilities at some times, especially small utilities without generation, operating in highly standardized markets. It is true that, if PacifiCorp finds at 9 AM that its

[25] Oddly, while agreeing to all these points, RMP refers to McDermott's Supplemental at 30–33, in which he accepts utility control only over fuel mix (which he considers an IRP issue), hedging, and ownership of fuel supply (at 31), and in which he repeatedly claims (at 32) that PacifiCorp has "little or no control over NPC."

load forecast for 10 AM has increased 20 MW, or that it has lost 20 MW of generation, it will have to do something to correct the balance. PacifiCorp's options include reducing a sale it had expected to make, increasing output from a fossil unit that is already operating, starting up additional generator (probably a combustion turbine), increasing output from a hydro unit at 10 AM and changing dispatch sometime later to allow the water level at the dam to recover, or purchasing power. Among purchases, PacifiCorp is not restricted to a single market; PacifiCorp reports purchases from about 120 parties at 73 locations during 2008, including 82 entities in the hour-ahead market (DR OCS 2.75a).[26] The Company has not found that those entities offer the same prices (DR OCS 2.75b). In July 2008, for any particular day (and separately for both LLH and HLH energy), PacifiCorp received offers from other parties that wanted to purchase power that varied widely, by an average of a three-fold ratio and often by five times or more. PacifiCorp certainly did not face a single market price.

Without an ECAM, PacifiCorp shareholders bear the cost of the 20 MW purchase and PacifiCorp has every institutional incentive to encourage its employees to select the least-cost supply. With an ECAM, ratepayers bear the cost of the 20 MW purchase and PacifiCorp has no incentive to do any more than is required by PSC oversight. As I discuss below, that oversight is much less complete than PacifiCorp's ability to control costs.

Q: Does PacifiCorp acknowledge that it has all the options you list in your previous answer?

[26]The number of parties is from PacifiCorp's FERC Form 1 at 346–347, excluding unit, long-term and intermediate purchases. Another 28 parties engaged in exchanges with PacifiCorp. The number of delivery points is from Attachment OCS 2-127.

A: No. PacifiCorp takes the position that it would not adjust dispatch in response to load changes, because its "plants are normally dispatched economically and independent of load levels" (DR OCS 2.16).

That would be a reasonable position if the change in conditions on the PacifiCorp system, including any resulting increase in PacifiCorp purchases from the market (or decreased sales into the market), had no effect on market prices. In reality, increasing loads (from RMP, the rest of PacifiCorp, or other Western utilities) will increase prices.

It is true that sometimes the incremental market price will happen to be much higher than the most expensive operating PacifiCorp unit and much lower than the least expensive PacifiCorp unit in reserve, considering ramp-up costs, cycling constraints, and the opportunity costs of using hydro in the current hour, rather than later. In this situation, a change in RMP load will result in PacifiCorp buying more power or selling less power, but not changing its generation. But in many hours of the year, PacifiCorp will have generation with running costs close to the market price; with higher load and the resulting higher market price, PacifiCorp's least-cost response would be to increase output at an operating unit, or to start up an additional unit.

C. Regulatory Scrutiny and Energy-Cost-Adjustment Mechanisms

Q: Which RMP witnesses argue that regulatory scrutiny will force PacifiCorp to be as efficient with an ECAM as it would be without an ECAM?

A: Mr. McDermott argues,

> 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.… This suggests that regulatory bodies are fully capable of reviewing fuel adjustment data and procurement procedures of utilities. (Supplemental at 39–40)

> the ECAM does not guarantee one penny of cost recovery as the utility will still need to demonstrate prudent operation. (Supplemental at 33)

and

> Rocky Mountain Power will still be required to justify every dollar that passes through the ECAM.... (Supplemental at 17)

Q: Is this position realistic?

A: No. As I discuss above (at 42), PacifiCorp's NPC is determined by many kinds of PacifiCorp decisions, made over a period of years by hundreds of people in many parts of the Company. PacifiCorp engaged in tens of thousands of gas and electric transactions in calendar 2008 (Confidential Attachment OCS 2.60), purchasing power at 73 locations (Attachment OCS 2.126) and selling power at 54 locations (Attachment OCS 2.127). Several times as many additional contacts, bids, and offers must have occurred between PacifiCorp and potential counterparties. There is no way to determine what communications that PacifiCorp might have originated, but chose not to. The PSC is in no position to monitor all of these power- and gas-trading communications, decisions, actions and inactions, let alone do the same for generation dispatch, power-plant and transmission maintenance, staff training, outage scheduling, and load forecasting. The PSC may never know about staff errors that never resulted in remedial responses, phone calls that were not made to potential trading partners, or delays in power-plant start-up while dispatchers finished lunch.

In most situations, a wide range of utility actions fall into a gray zone that is neither unequivocally optimal nor clearly imprudent. Running any large and complicated business, including a utility, requires many judgment calls: whether to sign a short-term or longer-term contract, when to seek new contracts, whether to accept reduced credit assurance or increased indexing in exchange for lower expected prices, and many more. Regulators are understandably reluctant to second-guess management decisions in that broad gray area, especially once hindsight has shown that the outcome was problematic.

Prudence reviews are often very demanding of time and resources, as should be clear from the reviews of the market problems and Hunter outage in 2000–2001.

Q: Is Dr. McDermott correct that, with an ECAM, PacifiCorp's power-supply function would have "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?"

A: No. For most other utility functions, PacifiCorp bears the costs of its decisions and actions for some time prior to reflecting those costs in rates. For some expenses that do not fall in any test year, PacifiCorp may never be reimbursed by ratepayers for any portion of the expense. For longer-term contracts and commitments, PacifiCorp bears the costs of the services until the effective date of the next rate proceeding. For capital investments, PacifiCorp bears the depreciation cost and earns no return until rates change.

PacifiCorp thus has an incentive to minimize most costs, even if it is confident that the costs will pass the prudence scrutiny. This is currently the case for NPC and almost all other costs; with an ECAM, the inherent cost-control incentives for NPC would disappear.

Q: Is RMP correct (DR OCS 2.59) that "the PSC would determine the prudence of the utility's actions in a similar manner as it determines the prudence of any cost that it allows into rates?"

A: No. For most costs, including NPC in Utah, the utility shareholders bear costs for some time before they are reflected in rates. Shareholders therefore have some skin in the game: an incentive to control costs. The PSC can rely on the utility's self-interest as the first defense against imprudence and inefficiency. With an ECAM, this protection disappears and the PSC must find other mechanisms for seeking out and remedying inefficiency and waste.

D. Practices of Other Jurisdictions

Q: How does RMP interpret the widespread use of ECAM-like mechanisms in other jurisdictions?

A: The Company interprets that practice as evidence that ECAM would not change PacifiCorp's cost-control incentives.

While RMP witnesses assert that national practice demonstrates the lack of an incentive problem, actual practice is quite diverse. The Company does not provide much detail on the specifics of each ECAM-like mechanism, but it is apparent that many jurisdictions recognize the incentive problem and have provisions to mitigate it.

Q: How many jurisdictions does RMP claim have some form of ECAM?

A: According to Exhibit KAM-2S, thirty-six states are "unrestructured," of which all but Utah have some form of ECAM for at least some utilities.

Q: Has RMP described these ECAM-like mechanisms?

A: No. Despite its reliance on practice in other jurisdictions, the Company was unable to describe the mechanisms, in terms of the share of costs flowed through the mechanism, adjustment caps and dead bands, generator performance requirements, categories on costs included, and whether the adjustment is based on actual fuel prices or market indices (DR OCS 2.66).

Q: Do the cost-recovery mechanisms for power costs in all of these jurisdictions support RMP's position?

A: Not in all cases, for four reasons. First, Tennessee does not have any regulated utilities that have any direct control over their power costs. Tennessee has only one investor-owned electric utility—Kingsport Power—that serves more than a dozen customers. Kingsport Power is a full-requirement customer of its affiliate Appalachian Power, so its power costs are set by FERC and not by the Tennessee Regulatory Authority.

Second, Dr. McDermott acknowledges that he is aware of "four jurisdictions that have specific incentive mechanisms in the ECAM…and nine others that have some form of partial cost recovery" (Supplemental at 39). Since two states—Arizona and Missouri—are in both lists (DR OCS 2.36, 2.68) and Dr. McDermott has corrected his count of partial recovery mechanisms to eight states (DR OCS 2.69), his count of states with cost-control incentives is ten.

Third, the Vermont Power Cost Adjustment Mechanisms are embedded in temporary and complex utility-specific settlements, which reduce the utility ROEs, limit total rate increases, limit the recovery of variable fuel and purchased-energy costs, and provide other ratepayer benefits. Thus, Vermont should have been in Dr. McDermott's list of jurisdictions with partial cost recovery, but is not (DR OCS 2.36).

Fourth, while Dr. McDermott counts Wisconsin as having a full ECAM, without any cost-sharing incentive mechanism, the Wisconsin PSC describes the Fuel Adjustment Clause (FAC) as follows:

> New FAC rates are set on a forward-going basis. Therefore, utilities have a financial incentive to control their costs to produce or purchase energy, since they are only allowed to recover increased future costs (not costs already incurred) if such costs for the year exceed a given threshold. (Wisconsin PSC, "Electric Residential Bill Comparison, Further Explanation of the Fuel Adjustment Clause (FAC)")[27]

I have not attempted to review the cost-recovery mechanisms of the other 33 states. By my count, excluding Tennessee as irrelevant, 12 of the 35 un-restructured states have been identified as imposing incentives in the ECAM-like mechanism, implying that they believe that an ECAM weakens the normal cost-control incentives.

Q: Dr. McDermott also mentions the power cost pass-through mechanisms of the 14 states he lists as restructured (Supplemental at 35). Do ratepayers in those states generally bear the risks of changes in fuel prices, markets, loads, forced outages and other factors after the power rate is set?

A: No. In most cases, power suppliers assume those risks, which are incorporated in the power rate, along with the risk of migration to or from the utility power supply option.

Q: Can the oversight of power procurement for the utilities in those states be reproduced in the Utah context?

A: No. Dr. McDermott claims no familiarity with these procurement methods (DR OCS 2.70). In most of the restructured states, utilities purchase only a small number of standard full-requirements products, under close scrutiny, in periodic competitive processes, conducted annually or a few times a year. In New Jersey, the procurement is a highly formalized state-wide process. In Maine and Illinois, a state agency runs the procurement auction. In Maryland and Connecticut,

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[27] http://psc.wi.gov/apps/electricbill/content/definition.htm#FAC, accessed 11/13/2009.

consumer advocates and consultants to the regulators are involved in the selection of the winning bids.

It would not be practical or efficient for the Utah PSC, the Division, and the Office to have staff or consultants continuously supervising PacifiCorp trading and dispatch on site, let alone generation and transmission operations.

VII. Conclusions

Q: Is there any need to change the PSC's existing practice with regard to recovery of NPC?

A: I do not believe that any such need has been demonstrated. Various RMP witnesses have hinted that past PacifiCorp cost forecasts have been biased downward. If that is the basic problem behind RMP's ECAM Application, PacifiCorp should improve its forecasting to remove that bias.

Dr. McDermott agrees that the standard for fair ratemaking is "providing a reasonable opportunity for cost recovery at the time rates are set" and that only "in cases in which that opportunity cannot be provided,… regulation must provide another method to provide the utility with a fair opportunity to recover prudently incurred costs." (DR OCS 2.78) The Company has not demonstrated that RMP has not been provided a reasonable opportunity for cost recovery.

The Company agrees that "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" (McDermott Supplemental at 18).

Dr. McDermott asserts that the PSC's methods and precedent for approving NPC costs in rate cases fails the standard he lays out (DR OCS 2.44a).

Unfortunately, when asked to explain why the PSC's approach produces the wrong results on average, Dr. McDermott responds by explaining why the actual NPC for an individual year may vary from the forecast (DR OCS 2.44b).

As RMP admits, the Company's forecast of NPC has been lower than actual NPC for most of the period 2002–2008 (DR OCS 2.5, OCS 2.44c).

If the Commission wants to encourage RMP to stay out for longer periods between rate cases, it might explore some alternatives to ECAM that maintain PacifiCorp's cost-control incentives.

Q: Do you have any recommendations regarding the structure of an ECAM, if the Commission were to decide that one was justified?

A: Not at this time. It is my understanding that performance incentives, cost sharing, and other design features would be considered in Phase II of this proceeding, if the Commission determines that an ECAM is desirable.

Q: Does this conclude your testimony?

A: Yes.