Q. Please state your name, address and current position.

A. My name is Frank C. Graves. I am a principal of *The Brattle Group*. My business address is 44 Brattle Street, Cambridge, Massachusetts 02138.

Q. Have you previously testified in this proceeding?

A. Yes, I submitted prepared supplemental testimony in this proceeding on behalf of Rocky Mountain Power ("RMP" or "Company") on August 12, 2009.

Q. What is the purpose of your rebuttal testimony?

A. I respond to various intervenors who assert that:

- the overall need for an ECAM has not been established;
- an ECAM is not needed in light of RMP's gas and power hedging practices;
- incentives to operate efficiently will be lost under an ECAM;
- implementation of an ECAM requires a reduction to RMP's cost of capital
- an ECAM should not be adopted until RMP's hedging practices and reliance on market energy have been addressed and resolved

Q. Please summarize your conclusory responses to these intervenors.

A. The need for an ECAM is clear from the substantial, intrinsic uncertainty that RMP faces with respect to its net power costs (NPC). RMP's hedging practices do not and cannot eliminate enough volatility in NPC to make an ECAM unnecessary. In particular, two components of NPC—net short-term sales revenue and natural gas expenses—exhibit so much variability that an ECAM-like mechanism will be needed to protect RMP and its customers, even with RMP's substantial hedging practices. These two components of NPC are also extremely difficult to forecast, with the result being that past rate case projections of total

NPC have had annualized variances between actual and allowed costs of up to $300 million or more, on a total system basis. Moreover, there is no reason to think that variances between forecasts and actuals in one component of NPC necessarily will be offset by variances in other components in NPC, or that forecast variances will be short-lived or symmetrical around a mean of zero over a few years. These differences have the potential to be persistent and systematic such that significant under-recoveries or over-recoveries of NPC are possible, with the potential for financial harm to either RMP or its customers. In recent past years, the tendency seems to have been for the settlement forecasts to understate eventual costs, often dramatically. An ECAM will not improve the forecasts, but it will ensure that RMP is compensated precisely for the net fuel and power expenses it incurs on behalf of its customers, without any over- or under-recovery of these costs.

I. HEDGING CANNOT CONTROL RISKS SUFFICIENTLY TO ELIMINATE THE NEED FOR AN ECAM

Q. What arguments have been raised by intervenors to suggest that an ECAM is not needed or is not in the public interest?

A. Mr. Paul Chernick claims that RMP has failed to provide a quantitative analysis of the magnitude and nature of the factors driving fluctuations in its NPC and that RMP "grossly exaggerates" the uncontrollable risks to which RMP is exposed without an ECAM.[1] He claims that even if RMP had been exposed to gas and electric price risks in 2002-2008, it is protected from price swings because of its

[1] Direct Testimony of Paul Chernick, p. 5 (lines 117-121).

gas and electricity hedging practices.[2] Mr. Kevin C. Higgins also finds that as a result of its hedging practices, RMP's cost structure is not sufficiently volatile to justify adoption of an ECAM.[3] Mr. Charles E. Peterson similarly believes that RMP has not been "entirely persuasive" in supporting the need for an ECAM, though he does recommend moving forward to Phase II of the proceeding to sort out design and implementation issues because some type of ECAM may be in the public interest.[4] He claims that RMP has substantially shielded itself from volatility in spot market prices in electricity and gas through its hedging practices and that RMP has not shown how volatility affects the Company's earnings.[5] Importantly, none of these intervenors offer a theory of what threshold of risk has to be crossed before they would deem the situation worthy of an ECAM, nor have any of them analyzed actual financial performance or the shifting (and increasing) nature of electric power market risks over the past few years and likely into the future.

Q. How do you respond to these claims?

A. I disagree with the suggestion that RMP's hedging practices make an ECAM unnecessary and that RMP has exaggerated the uncontrollable risks to which it is exposed. The need for an ECAM can be seen in the significant uncertainty RMP faces with respect to at least two major components of its net power costs, specifically net revenues from short-term power sales and purchases (that are a deduction from RMP's NPC given RMP's position as a net seller of energy but

[2] *Id*, p. 10 (lines 239-243).
[3] Prefiled Direct Testimony of Kevin C. Higgins, p. 3 (lines 61-63).
[4] Direct Testimony of Charles E. Peterson, p. 4 (lines 81-83), p. 5 (lines 100-102), and p. 6 (lines 122-126).
[5] *Id*., p. 5 (lines 104-107).

not capacity) and natural gas expenses. These components are sources of considerable NPC risk for RMP—risk that it cannot control to any significant degree.

At the time it files a general rate case, RMP makes projections of these two components (and other factors) of its net power costs, but there is unavoidable uncertainty as to both their realized volumes and the prices at which they will occur. The price component is very uncertain because spot prices are highly volatile and almost certain to diverge from prior forward prices. Indeed, forward prices themselves change rapidly, making the forecasting process highly dependent on the dates when the analysis and filing occur. The volumes for short-term sales and purchases and for natural gas expense in turn depend on the realized spot prices, and on complex, shifting supply conditions. There are simply too many unknowns to expect RMP to make a clairvoyant forecast of these items that will reliably have small variances from actuals. Moreover, NPC rates are not set based strictly on RMP's own, most timely projections prevailing just before the filing. Instead, they reflect lags in a process that includes the opinions of intervenors about how markets may evolve or how the PacifiCorp system may be operated. The historical evidence presented by Mr. Gregory N. Duvall demonstrates that the resulting variances have been large and have lead to substantial under-recovery of RMP's NPC (though in principle over-recovery could also occur).

Moreover, for some of the same reasons that these items are difficult to forecast (especially the highly uncertain volumes) RMP's hedging practices cannot make this uncertainty go away, nor could a better forecasting model. At best, one can project these costs within a broad confidence interval reflecting the uncertainty in the short-term power and gas markets. An ECAM is necessary to capture these variances and ensure accurate recovery of incurred costs.

Q. Please describe your analysis of how net short-term power sales revenues and natural gas expenses contribute to NPC?

A. I have developed some summary statistics on the major components of projected NPC since 2001 for PacifiCorp as a whole (the level at which NPC is managed). These values are taken from Exhibit RMP___(GND-1R) (described in the rebuttal testimony of Mr. Duvall) and they are presented as tables in my Figures 1, 3, 4, and 5 throughout this testimony. I have simply normalized his data to put it on an annualized (12-month, not calendar) basis, and then I have calculated some ratios that show how much certain cost components contributed to NPC. This analysis describes the annualized costs that were projected (or realized, in some rows) on average over a 12-month period for the items in a given NPC filing, averaging across all the months between filings.

The "projected" rows in my analyses are calculated as if the rates approved in the RMP filings applied to the entire PacifiCorp system, in order to show conceptually how much of an economic gap there would be for the corporation as a whole if all of its cost recovery was based on Utah RMP rates. In fact, this is not the case, as some of the other PacifiCorp state jurisdictions have ECAM-like adjustment clauses that protect against the kinds of variances seen in this chart. RMP in Utah represents approximately 40 percent of PacifiCorp's total load, so roughly speaking, RMP's exposure is to that share of these overall variances.

Q. What does your analysis demonstrate about the causes of NPC variability?

A. The first four rows of Figure 1 below show the three major components of NPC to have been net short-term sales revenues (the difference between short-term sales and short-term purchases, labeled "NSR" herein for convenience), gas expenses, and other expenses (mostly coal operating costs, long term power purchases and sales, and fuel contracts). Rows 5 and 6 show that NSR and gas expenses have made up a significant portion of forecasted annual NPC.

Figure 1
Major Projected NPC Components, Annualized (Million $)

		A	B	C	D	E	F
	Docket No.	**01-035-01**	**03-2035-02**	**04-035-42**	**06-035-21**	**07-035-93**	**08-035-38**
	Effective Date	9/15/01	4/1/04	3/1/05	5/31/07	8/13/08	5/8/09
	Number of Months Rates in Effect	27	11	27	14	9	5
[1]	Net Short-Term Sales less Purchases (NSR)	(218)	229	248	527	439	669
[2]	Gas Expenses	(25)	(66)	(108)	(181)	(345)	(467)
[3]	Other Expenses	(345)	(675)	(861)	(1,159)	(1,099)	(1,232)
[4]	**Net Power Costs (NPC)**	**(588)**	**(512)**	**(720)**	**(813)**	**(1,006)**	**(1,030)**
[5]	NSR as % of NPC	37%	-45%	-34%	-65%	-44%	-65%
[6]	Gas Expenses as % of NPC	4%	13%	15%	22%	34%	45%

Sources and Notes:
[1] - [4]: From Rocky Mountain Power.
[5]: [1] / [4]
[6]: [2] / [4]
*Figures may not add up due to rounding.
**Expenses that reduce net income and increase NPC are shown as negative numbers.
***Other expenses include coal operating costs, long term power purchases and sales, and fuel contracts.

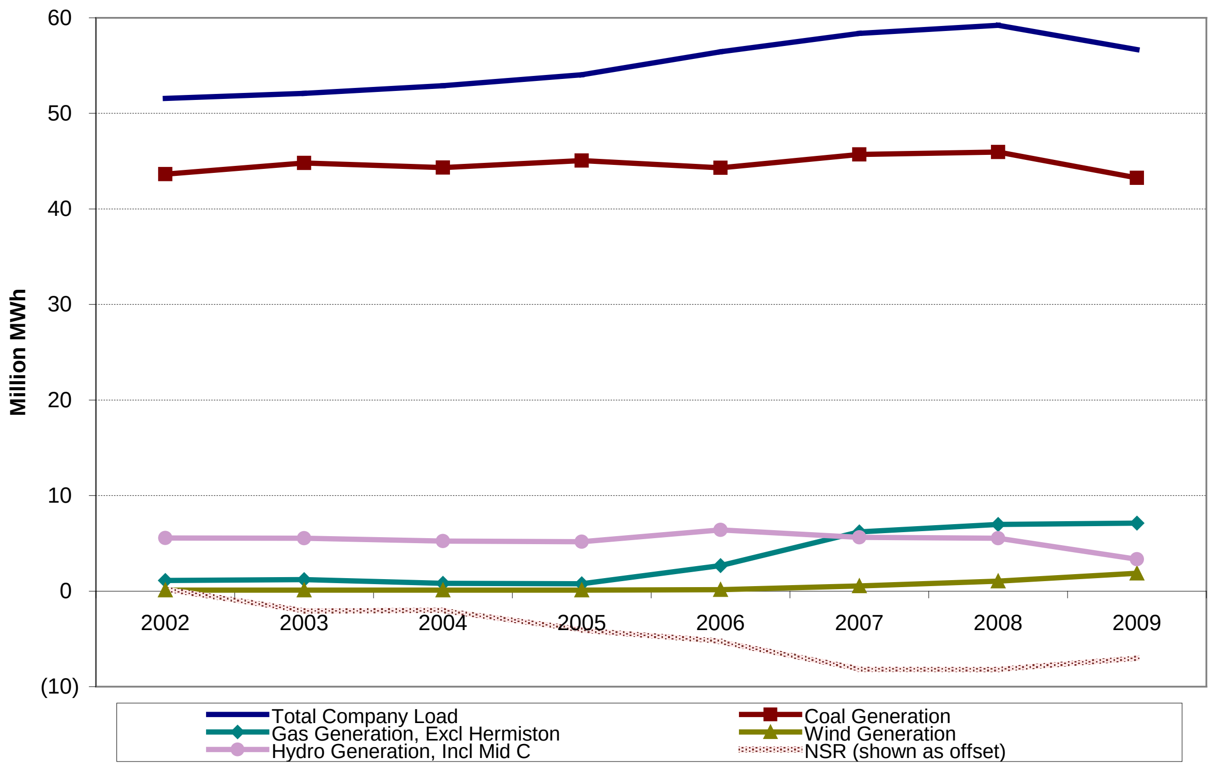
Specifically, projected NSR has ranged from negative $218 million (i.e. net purchases) in 2001 to as much as positive $669 million most recently, or as much as negative 65 percent, of annual NPC, which itself has been a bit above $1 billion per year at the time of the more recent rate cases. NSR is usually a negative percentage of NPC because it serves to lower NPC. This happens because, since 2001, RMP has projected it will earn net positive sales margins (from its short-term balancing sales in excess of purchases) with the net revenues credited against the other expenses that make up NPC. For instance, in Docket No. 06-035-21, RMP filed a rate case in which it projected $1,076 million in short-term market sales, less $549 million of projected purchases, for a net of $527 million shown in Row 1, Column D of Figure 1. This amount was used to reduce roughly $1.34 billion in gas and other operating expenses, for an overall NPC of about $813 million.

Likewise, RMP's natural gas expenses are a significant portion of NPC, which has grown significantly over the past decade as more gas resources have been added to the PacifiCorp supply portfolio. Gas expenses have accounted for roughly $181 to $467 million or 22 to 45 percent of annual NPC in recent rate cases.

Q. Is there evidence that RMP is increasingly relying on resources whose costs are difficult to forecast?

A. Yes. Figure 2 below shows the actual annual load and key resources on the RMP system during most of this decade. Loads have been growing over the course of the decade, while coal-fired generation has remained a relatively stable source of supply, operating at similar levels to those of the early part of the decade. Therefore, these expanded obligations are being met increasingly by gas-fired generation and renewable resources. Also shown in this figure is a line below the x-axis that shows the NPC offsets from NSR.

Figure 2
Generation Mix and Load (Million MWh)



Note: 2009 figures are scaled up to annualize 9 months of actual data.

Q. Why are short term sales and purchases difficult to forecast?

A. These transactions are for "balancing" the system via selling residual power to the wholesale market in off-peak periods when it is not needed for native load, and buying supplemental power when owned resources are not enough, or the PacifiCorp marginal units are not as economical as market sources, to meet native load requirements. This balancing takes place opportunistically over hours, days, or somewhat longer periods, but not over the forecasting horizon of NPC filings. Thus it depends on many factors that simply cannot be known with any precision at the time of a rate filing. While RMP can use system models to reasonably simulate in advance the hours, quantities and prices at which it expects it will buy and sell balancing electricity, how much it ultimately transacts will depend on realized short-term supply and demand market conditions in both its service territory and in adjacent service territories throughout the WECC.

For instance, if actual load is higher than was projected in rates, then purchases (or gas expense) are also likely to be higher. Off-system sales may or may not then be higher, depending on whether PacifiCorp's generation resources remain available for resale despite the higher native loads, and on how their operating costs compare to the marginal cost resources serving the wholesale market. The latter, in turn, could depend on outages on the Western interconnection system, transmission constraints, hydro conditions, and many other highly uncertain variables. There are two important implications of this complexity from being a residual resource involved in balancing: First, the underlying sales and purchase volumes are highly conditional and variable from day to day and hour to hour. This makes them very difficult to hedge accurately, because they are not in any way similar to standard, fixed volume and fixed price forward contracts for fuel or power. Second, it makes them very difficult to forecast.

Q. How variable has NSR been in the past few years?

A. It has been extremely variable, in terms of its forecasted vs. actual sales and purchase volumes, sales and purchase prices, net amounts for each, and overall NSR projected in-rates versus actual total dollars. The last four rows of Figure 3 show these components over time. The annualized variances between forecasts and actuals in NSR have ranged from positive $264 million (actual NSR far exceeding projected amounts) to negative $214 million (an NSR shortfall from projected amounts), or from -26 percent to 42 percent of projected NPC in rates.

Figure 3
Net Short Term Sales and Purchase Revenues (NSR), Annualized

		A	B	C	D	E	F
	Docket No.	**01-035-01**	**03-2035-02**	**04-035-42**	**06-035-21**	**07-035-93**	**08-035-38**
	Effective Date	9/15/01	4/1/04	3/1/05	5/31/07	8/13/08	5/8/09
	Number of Months Rates in Effect	27	11	27	14	9	5
[1]	Projected Sales (million MWh)	14,344,413	21,093,843	10,767,502	16,105,936	18,998,101	14,743,701
[2]	Actual Sales (million MWh)	20,586,470	22,183,806	30,600,294	35,183,630	21,977,864	16,671,099
[3]	Projected Sales Price ($/MWh)	$57.29	$41.06	$43.89	$66.82	$64.28	$63.39
[4]	Actual Sales Price ($/MWh)	$33.51	$43.79	$54.35	$62.30	$59.19	$43.60
[5]	Projected Sales (million $)	822	866	473	1,076	1,221	935
[6]	Actual Sales (million $)	690	972	1,663	2,192	1,301	727
[7]	Projected Short Term Market Purchases (million $)	1,040	637	224	549	783	266
[8]	Actual Short Term Market Purchases (million $)	663	957	1,372	1,743	598	246
[9]	Projected NSR (million $)	(218)	229	248	527	439	669
[10]	Actual NSR (million $)	26	15	292	449	702	481
[11]	Forecast Variance in NSR (Actual - Projected)	245	(214)	44	(78)	264	(188)
[12]	Forecast Variance as % of Projected NSR	-112%	-93%	18%	-15%	60%	-28%
[13]	Forecast Variance as % of NPC In Rates	-42%	42%	-6%	10%	-26%	18%

Sources and Notes:
[1] - [10]: From Rocky Mountain Power.
[11]: [10] - [9]
[12]: [11] / [9]
[13]: [11] / NPC (Table 1, [4]).
*Figures may not add up due to rounding.
**Expenses that reduce net income and increase NPC are shown as negative numbers.

For example, the NSR projected in Column E, Row 9 (following Docket 07-035-93) was $439 million, but actual NSR was $264 million higher (roughly $702 million). The variance was -26 percent of the projected NPC (which was about $1.0 billion) and 60 percent of the projected NSR. The upper rows in this chart break out what caused the variance. The first two rows show projected and actual short term sales volumes, in million MWh/year. Projected sales in this docket were much lower than actual, with 22.0 million MWh sold versus 19.0 million MWh projected. The next two rows show that the average price per MWh at which these sales occurred was roughly $5/MWh less than projected. Thus, the overall revenues from short term sales were $1,301 million versus $1,221 million projected, for an $80 million variance due to these price and quantity effects combined. The actual short term purchases in that rate period also did not match the projected amounts in rates, with actuals of $598 million compared to a projection of $783 million, for a net purchase variance of $185 million. The total NSR variance of $264 million is the sum of these two (sales and purchase) variances, favorable to RMP's cost recovery in the 2007 case. However, such an offset was not the result arising from the variances in the prior and subsequent rate settings, in which actual NSR was below projected, contributing to an annualized under-recovery of total NPC.

Studying the rows and columns of Figure 3 reveals large variability in these components over time. For instance, actual 12-month short-term market sales have ranged from $690 million to $2,192 million and have swung up and down substantially from rate case to rate case. Likewise, actual short-term market purchases have varied substantially over time. Thus, NSR credited against other costs in NPC represents the net value of two huge line items, themselves often much larger than NPC, and both facing very complex volume and price forecasting problems.

Q. Have there also been significant variances between forecasts and actuals with respect to the natural gas component of NPC?

A. Yes there have, and for similar reasons to the difficulties in projecting NSR. Gas generation is also a residual quantity, since it dispatches towards the top of the merit ladder, after baseload coal, hydro and renewables. And like NSR, gas expense reflects both complex, conditional short-term volumes and uncertain gas fuel prices. There is significant uncertainty in the projections for RMP's gas-fired generating units as to how much they will run, how much natural gas they will consume, and at what price. Figure 4 below shows that the annualized variances have ranged from negative ($42) to positive $185 million or +8 to -23 percent of projected NPC.

Figure 4
Gas Expense Variances

		A	B	C	D	E	F
	Docket No.	**01-035-01**	**03-2035-02**	**04-035-42**	**06-035-21**	**07-035-93**	**08-035-38**
	Effective Date	9/15/01	4/1/04	3/1/05	5/31/07	8/13/08	5/8/09
	Number of Months Rates in Effect	27	11	27	14	9	5
[1]	Projected Gas Expenses (millon $)	25	66	108	181	345	467
[2]	Actual Gas Expenses (million $)	42	24	80	366	479	468
[3]	Forecast Variance (Actual - Projected)	17	(42)	(27)	185	134	1
[4]	Forecast Variance as % of NPC In Rates	-3%	8%	4%	-23%	-13%	0%
[5]	Projected Gas Generation (Excl. Hermiston) (MWh)	588,244	1,478,264	2,146,539	3,975,612	5,700,246	7,731,378
[6]	Actual Gas Generation (Excl. Hermiston) (MWh)	1,075,611	880,147	2,246,758	6,928,205	7,781,709	6,887,016
[7]	Forecast Variance (MWh) (Actual - Projected)	487,367	(598,118)	100,218	2,952,593	2,081,463	(844,362)
[8]	Forecast Variance as % of Projected Generation	83%	-40%	5%	74%	37%	-11%
[9]	Projected Gas Price ($/MWh)	$42.21	$44.89	$50.17	$45.49	$60.61	$60.39
[10]	Actual Gas Price ($/MWh)	$38.71	$27.40	$35.73	$52.85	$61.60	$67.95

Sources and Notes:
[1] - [2], [5] - [6]: From Rocky Mountain Power.
[3]: [2] - [1]
[4]: [3] / NPC (Table 1, [4]).
[7]: [6] - [5]
[8]: [7] / [5]
*Figures may not add up due to rounding.
**Numbers are shown as negative when they decrease NPC and increase net income because gas is an expense in this figure.

For example, the gas expenses projected in Column E (again following Docket 07-035-93) were $345 million, but actual gas expenses were over $134 million higher ($479 million). This occurred because actual gas generation was much higher than had been projected (7.8 million MWh actual versus 5.7 million MWh projected). The result was a large under-recovery, resulting in an additional $134 million in gas costs that were not included in the rate case projection for gas expenses. (In this period, very little of the variance in gas expense is due to gas prices themselves, for which projected and actual values were quite similar. However, in other periods, the price variances were large). It is likely that some of this gas variance occurred in lieu of the short-term purchases discussed above, which were lower than projected over this same time frame. Sometimes, that kind of NPC variance-dampening relationship will hold (in which gas generation substitutes for purchases, or gas is used more heavily to cover increased short term sales), but it need not occur, depending on when and why more purchases or sales are needed.

Q. Can't gas expenses be hedged fairly readily, given the active markets trading forward at several locations?

A. Yes and no. Fixed volumes of gas can be hedged quite readily, but that does not describe the RMP usage of this fuel. As explained above, RMP's gas needs arise from a complex, residual power requirement in the top of the dispatch supply that can change from day to day due to combinations of natural gas spot prices, wholesale power prices, and operational reliability considerations. Thus, the actual volumes of gas ultimately dispatched will depart from the amounts hedged and in rates, because gas-plant utilization is dependent on short-term system conditions.

Even though the expected gas needs are hedged with forward purchases, the price paid in such forwards does not determine whether the gas units will be dispatched. Because there is such an active, liquid spot market in natural gas, it is more economical for these units to be dispatched according to whether the short-term price of gas justifies their usage, not according to whether the hedged price would do so. If the spot price for gas is above the price at which the unit should dispatch, but the hedged gas is less expensive, the hedged gas itself is sold to the spot gas market rather than used as fuel in the less valuable electric generation; power is purchased in the spot power markets to replace the gas-fired generation not used.

Q. Do the problems you have identified with respect to forecasting NSR and gas expenses translate into substantial variance between forecasts and actuals for overall NPC?

A. Yes. Figure 5 compares forecasted to actual NPC on both a total cost (millions of dollars per twelve months) and average cost ($/MWh) basis. It shows there has been a substantial gap, almost always adverse to RMP shareholders, between allowed and actual NPC. The annualized variances are as much as $308 million in unrecovered costs, with the differences ranging from +3 percent over-recovery to -52 percent under-recovery and with only one period out of six in which actual NPC was below the projected (in-rates) NPC. Column D provides a good example. In total, actual NPC was $1.1 billion, compared to projected NPC of $813 million—for an under-recovery of $308 million. This under-recovery is largely explained by the variability in NSR ($78 million, see Figure 4) and natural gas ($185 million, see Figure 3).

Figure 5
Overall NPC Variances

	A	B	C	D	E	F
Docket No.	**01-035-01**	**03-2035-02**	**04-035-42**	**06-035-21**	**07-035-93**	**08-035-38**
Effective Date	9/15/01	4/1/04	3/1/05	5/31/07	8/13/08	5/8/09
Number of Months Rates in Effect	27	11	27	14	9	5
[1] Projected NPC In-Rates (Total Cost)	588	512	720	813	1,006	1,030
[2] Actual NPC (Total Cost)	631	780	797	1,121	974	1,128
[3] Forecast Variance (Actual - Projected)	43	268	77	308	(32)	98
[4] Forecast Variance as % of NPC In Rates	-7%	-52%	-11%	-38%	3%	-10%
[5] Projected NPC, Average Cost ($/MWh)	$11.13	$9.99	$12.93	$14.45	$17.20	$17.22
[6] Actual NPC, Average Cost ($/MWh)	$12.14	$14.70	$14.38	$18.75	$16.85	$19.81
[7] Average Cost Variance as % of Projected Cost	9%	47%	11%	30%	-2%	15%

Sources and Notes:
[1] - [2]: From Rocky Mountain Power.
[3]: [2] - [1]
[4]: [3] / NPC (Table 1, [4]).
[5] - [6]: From Rocky Mountain Power.
[7]: ([6] - [5]) / [5]
*Figures may not add up due to rounding.

In this particular time period, the variance in natural gas costs was not offset by a corresponding variance (in the other direction) of NSR, although that sometimes can happen. For instance, in the Column E of Figure 4, a similarly large gas cost under-recovery (of $134 million) was more than offset by the much higher than forecast actual NSR (of $264 million) that I described in Figure 3. As shown in Figure 5, the end result in this one instance was an over-recovery in NPC of $32 million (See Column E, Row 3). Higher market prices for power might result in higher sales and higher gas usage, thereby having one factor offset the other, but (as discussed further below) there is no reason to assume that this will occur in general.

II. INCREASED DIFFICULTIES IN FORECASTING

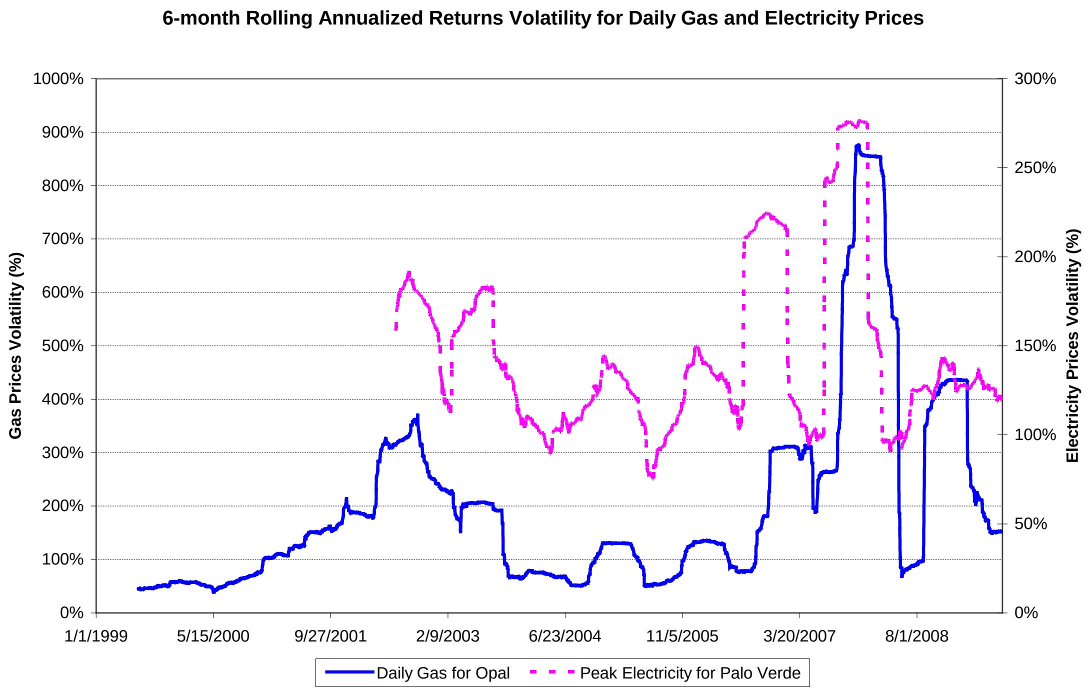
Q. Do changing wholesale market conditions also contribute to the difficulty in forecasting NPC?

A. Yes, another contributing factor is that wholesale gas and power prices have become harder to forecast, even apart from the fact that the quantities needed by

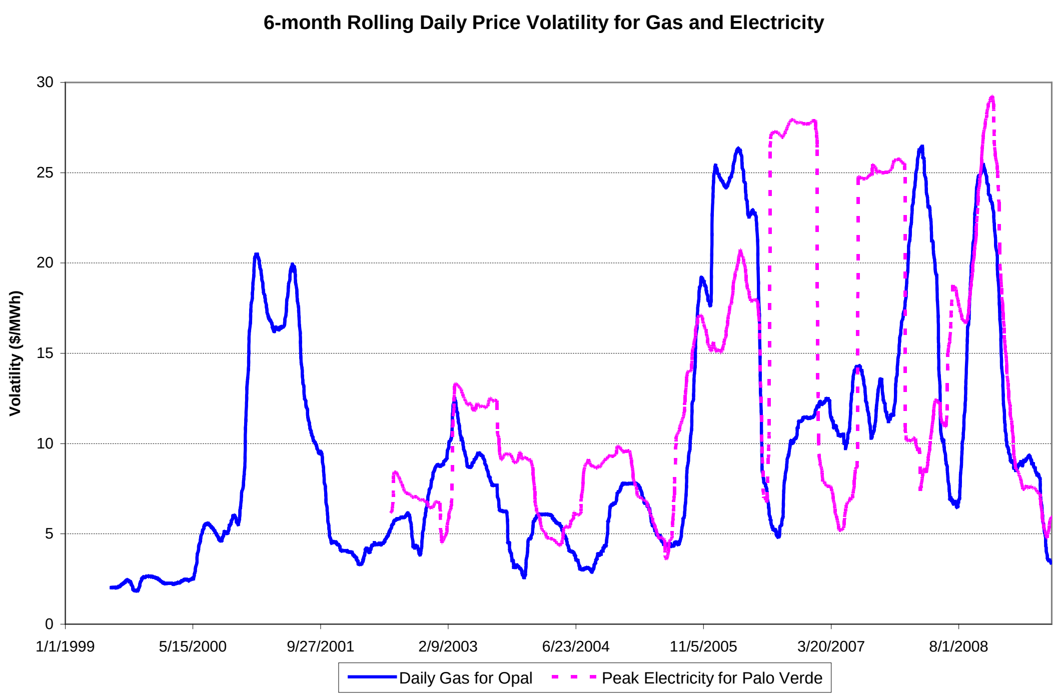
RMP are residuals with complex time patterns. Just the price forecasting problem alone, apart from any volume shaping or timing problems, has become more difficult in the past few years. Specifically, volatility in gas and power prices has increased. Figure 6 shows the 6-month rolling volatility of natural gas spot prices at Opal and the 6-month rolling volatility of electricity peak prices at Palo Verde. The upper figure shows the annualized percentage day-to-day changes in prices, while the lower figure shows the volatility of the prices in $/MWh terms. Both charts show the increasing volatility over the last few years, but especially the dollar-denominated charts. (The upper, percentage chart is more typically reported as a measure of volatility, especially for use by power traders, but the lower chart in actual price terms is more useful for understanding the variances RMP has experienced in its NPC collections vs. forecast.)

This increasing volatility of spot prices contributes to the difficulty in projecting likely NSR volumes and prices, and gas expenses. It means there is an increasingly wide range of realized spot prices at the time those short-term transactions actually take place.

Figure 6



Sources and Notes: Daily Gas data is for Kern River, Opal from Platts Gas Daily and Electrcity data is for Palo Verde from IntercontinentalExchange (ICE). Rolling volatility is calculated using the previous 124 observations (roughly 6-month history).



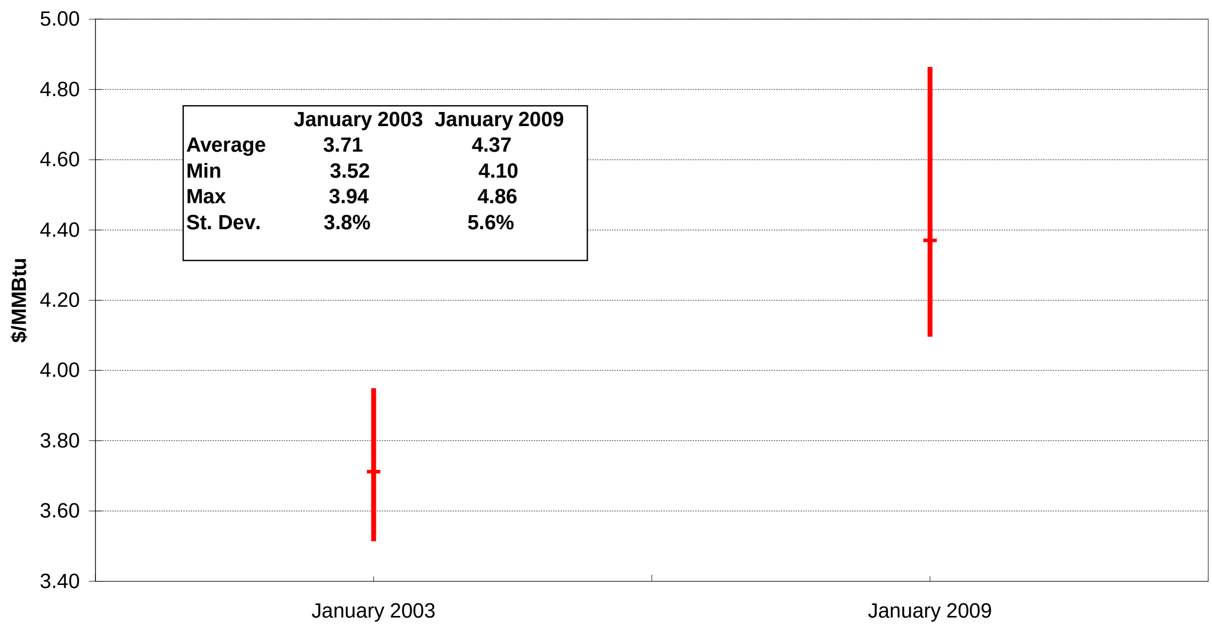
Sources and Notes: Daily Gas data is for Kern River, Opal from Platts Gas Daily and Electrcity data is for Palo Verde from IntercontinentalExchange (ICE). Rolling volatility is calculated using the previous 124 observations. Gas prices in $/MMBtu are converted to $/MWh at 10,000 heat rate.

Q. What about forward prices? Have they become more volatile as well, and if so, how does that contribute to increased forecasting difficulties?

A. Forward prices for power and natural gas have both become more volatile over the past few years, consistent with the spot price behavior just discussed. Figure 7 shows some statistics obtained from the recent (January 2009) and historical (January 2003) daily data on forward gas prices for the Rocky Mountain area at Opal. This figure shows the average, minimum, maximum and variability (measured by standard deviation) of the natural gas 12-month forward strip average price six months ahead of delivery. In January 2003, the average forward prices of natural gas for delivery at Opal in July 2003 through June 2004 was \$3.71/MMBtu, the spread between the highest and lowest values was \$0.42/MMBtu and the standard deviation was 3.8 percent of the average value. By January 2009, the average forward strip prices had increased by \$0.66/MMBtu, while the spread between the highest and lowest values had almost doubled (increased to \$0.76/MMBtu) and the standard deviation increased to 5.6 percent.

Figure 7

Average, Min and Max of Natural Gas 12-Month Forward Strip for Rock Opal (6-Month Ahead Delivery)



The significantly broader range of forward prices in 2009 comparative to 2003 indicates increased uncertainty, which makes the NPC forecasting problem much more difficult, especially since RMP forecasts its prices primarily based on market forward prices. That is, even though forward prices may be the current best estimate of future spot prices, in recent years such estimates have become increasingly variable from day to day. This means that the prices used as the anchoring basis for projected NPC prices in a rate case would very likely be different, perhaps materially so, if they had been based on forward contracts trading just a day or two earlier or later than the trading dates actually used. Thus, there is no real hope of reducing NPC risk through “better forecasting.” The market already impounds the consensus forecast of the marginal traders, day in and day out, and that forecast has become quite variable.

Q. Does forward price volatility aggravate the risks due to regulatory lag?

A. Yes, forward price volatility creates NPC recovery exposure to the lag between the start of the test year period and the date when rates go into effect. If rates go into effect well into or after the test year, the allowed amounts will not reflect the actual costs of hedges and forward contracts that are new by the time the rates become effective, instead reflecting the maximum of forward commitments and hedges in effect during the test year. The greater the volatility of forward contracts (and the larger the gap between the test year and the effective date of the rates), the greater the potential variance. In RMP's current rate case, the test year period is from July 2009 to June 2010, while the associated rates are expected to go into effect in February 2010, a seven month delay.

Q. Is a similar increased uncertainty observed in forward power prices?

A. Yes, uncertainty in forward power prices has also increased over the last couple of years. Figures 8 and 9 show the increased variability in the 12-month forward strip trading six months ahead of delivery for on-peak and off-peak contracts at Palo Verde. The average peak-hours' electricity forward price increased by $4.96/MWh from January 2003 to January 2009, i.e. by about 10 percent, while the difference between the highest and lowest value and the standard deviation more than doubled over the same time period. Off-peak electricity forward prices exhibit an even more dramatic increase in uncertainty, as evident from Figure 9. The average off-peak electricity forward price increased by $8.34/MWh from January 2003 to January 2009, while the difference between the highest and lowest value almost tripled and the standard deviation more than doubled over the same time period. Again, this increased volatility of forward prices means that the forecasted NSR could vary significantly simply by using alternative trading dates for the reference forward contracts. Projected gas expenses will also vary with the timing of the forecast, since gas dispatches in a manner that depends partly on the electricity market price curve.

Figure 8

Average, Min and Max of Peak 12-Month Forward Strip for Palo Verde (6-Month Ahead Delivery)

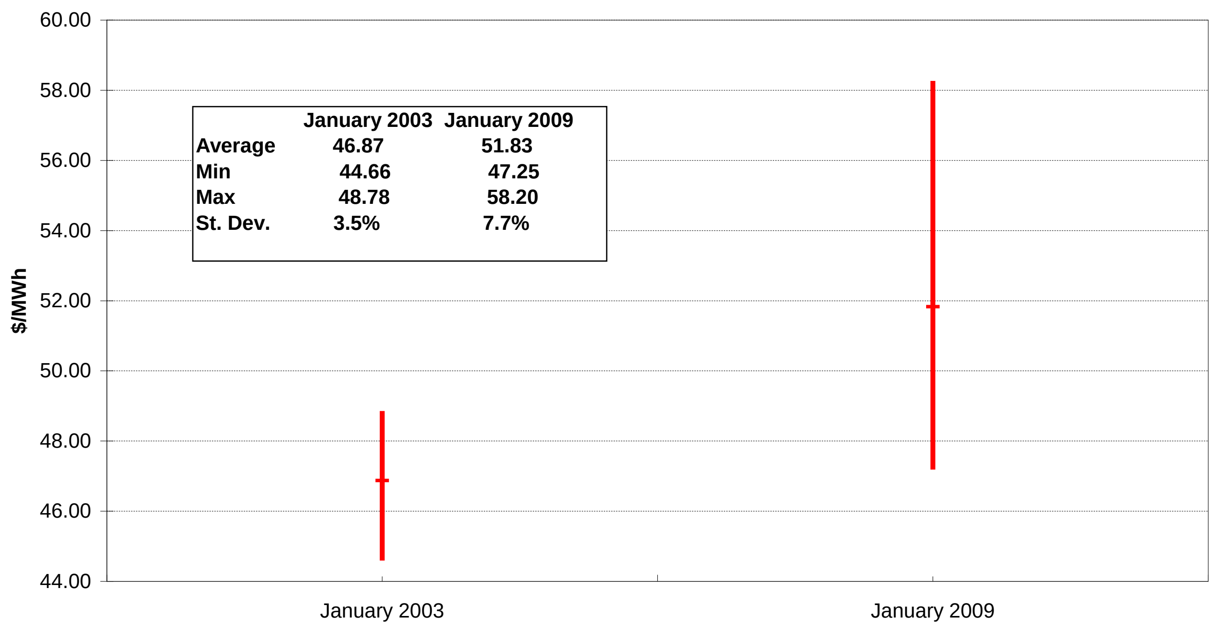
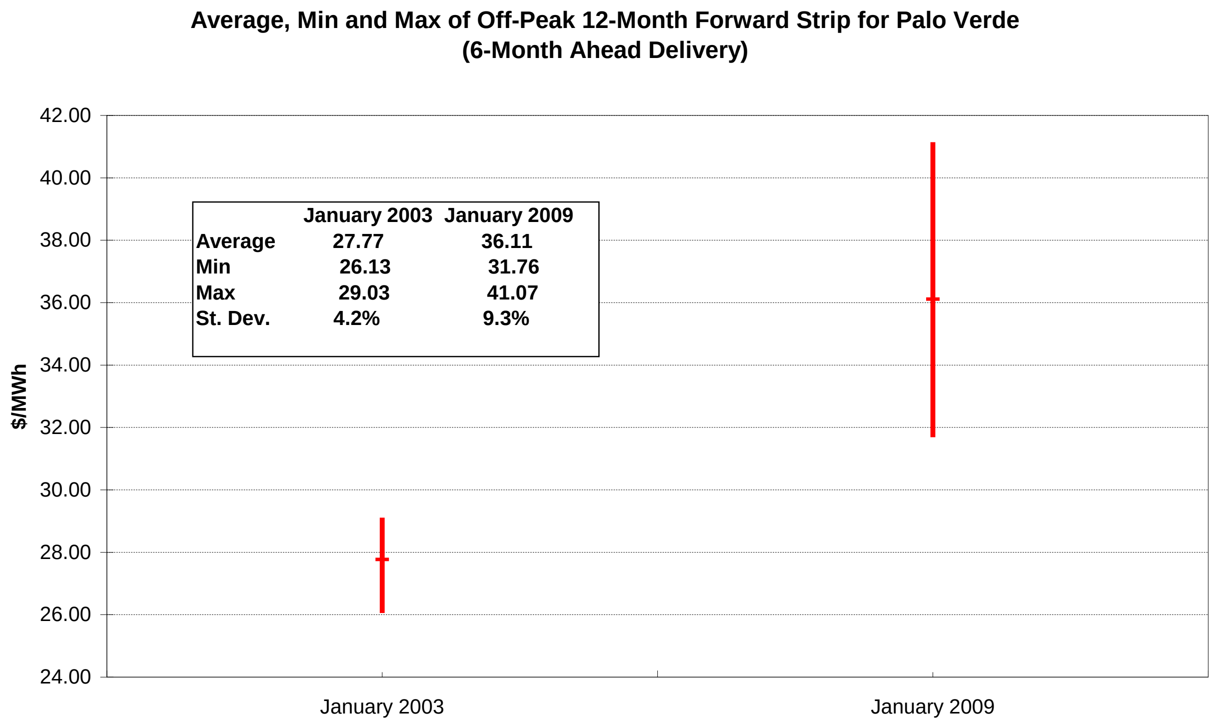


Figure 9



Q. How would these views of market price volatility have compared to the outlook for gas and power market volatility prevailing or expected at the time the EBA was eliminated?

A. The petition to cancel the EBA was filed in December 1990. At that time, the U.S. natural gas industry was experiencing a substantial, prolonged period of excess supply, and still displacing long-term take- or-pay gas with deep supplies of spot gas (induced by the 1978 Natural Gas Policy Act that gradually deregulated wellhead gas by 1985). By 1990, gas prices had been around $2/Mcf for a few years and were expected to stay near that level for several years (as they actually did until about 1997). Relatedly, the electric industry had an excess supply of generation capacity, due to a combination of large baseload plants that had been built ahead of loads, and the surge of mostly gas-fired, baseload "qualifying facilities" or QFs that were developed in response to PURPA. Wholesale restructuring of the electric industry had just occurred in England, but it was only a concept being debated for the U.S. among economists and some policy-makers at the FERC. It was not implemented until Order 888 in 1996 made open-access transmission a national requirement. Large-scale competition in wholesale power markets, with unregulated pricing by merchant generators, was not the norm until around 2000 when FERC Order 2000 fostered Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

In short, both power and gas markets looked very different in 1990 than today. Forward contracts for gas and electricity comparable to those whose prices were shown above were not available for several more years, and spot markets were thin and far less volatile than what we have observed over the past decade. "System lambda" (i.e., the time pattern of hourly short run marginal costs of dispatching a specific utility's generation fleet) was the reference point for power supply planning. Very few economists in 1990 would have offered a vision of the complex situation that RMP now faces. To the extent electricity competition was envisioned at all, the (now somewhat naïve) hope and expectation was that prices would become lower and less volatile for customers. Low-cost, natural gas-fired generation would supplant the lumpy, often expensive baseload capacity choices made in the past under regulation, and power plant owners rather than customers would bear the value and performance risk of those choices.

Unfortunately, the market realization has not always lived up to those expectations, with much more complicated markets for transmission and ancillary services, occasional market power abuses, dramatically increased spot energy volatility, boom-bust cycles, and other complications. While it may have seemed plausible to abandon the EBA in 1990, the reasons and market circumstances supporting that change no longer apply.

Q. Will variances between forecasts and actuals among factor inputs tend to offset each other?

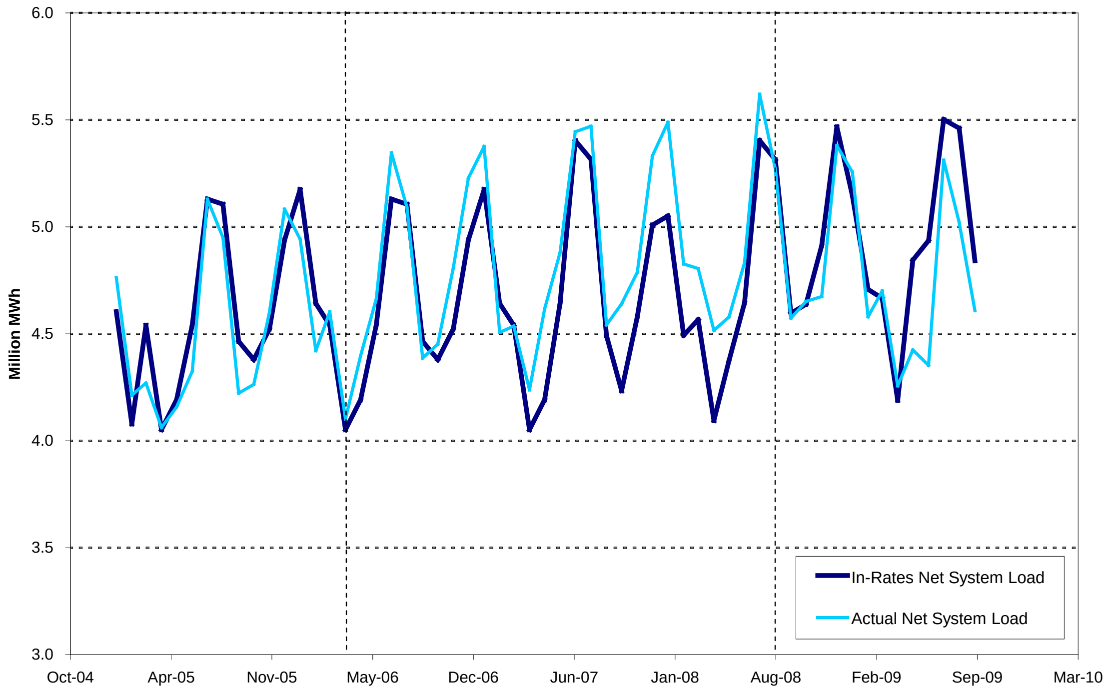
A. Not necessarily. Most of the very short-term, hourly or day-to-day variation in market conditions will tend to have positive and negative signs, but even those movements will not necessarily be offsetting. As I explained on pages 39-40 of my supplemental direct testimony, there tends to be a positive correlation between variances in forecasted quantities and spot gas or purchased power costs. For instance, if the actual load turns out to be higher than forecasted, a utility will need to cover the shortage through spot market purchases (either of power or of natural gas if its gas-fired power plants are available to generate at above-forecasted levels). When loads are high for RMP, they are likely to be high for neighboring utilities as well, so available supply is likely to be tighter and more costly. Thus supplemental purchases will often occur at higher prices than were originally forecast or locked in for the rest of the portfolio. Due to this positive correlation between variances in load forecasting and forecasted gas or purchased power prices, it is not necessarily the case that changes in forward demand forecast and gas and purchased power costs, which are the key input factors, will be offsetting.

Q. Can variances between forecasts and actuals in factor inputs persist over time?

A. Yes, a more serious problem than correlated short-term, unexpected movements in load and prices is long-term persistence in variances caused by systematic changes in market conditions and structure (e.g., drought, or changes in OPEC pricing, etc.). For example, a persistent under-estimation of net system load is evident in Figure 10 below, where the actual net system load is consistently above the forecasted (in-rates) net system load for over two years from March 2006 to late 2008. Also, systematic factors can combine to make a persistent variance in one factor also more costly than would have been expected. Higher than expected loads may occur if a year is abnormally warm at times when air conditioning is desired. But if such a year is also a drought year, then there may be a need for more gas generation than had been budgeted, and/or higher costs of net purchases (and more of them, to offset the lost hydro).

Figure 10

Net System Load Variances



Source: Data from Rocky Mountain Power

III. INCENTIVES TO OPERATE EFFICIENTLY WILL NOT BE LOST UNDER ECAM.

Q. Several intervener witnesses have expressed concerns that the ECAM will undermine incentives for RMP to be careful in its power and fuel procurement. Do you agree?

A. I am aware of these concerns. In particular, Mr. Chernick suggests that an ECAM will reduce RMP'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,"[6] while Ms. Michele Beck expresses concern about potential incentive problems

[6] Direct Testimony of Paul Chernick, p. 41 (lines 977-980).

inherent in ECAM-like mechanisms.[7] In theory, these concerns have some validity. However, I believe they are mistaken for three reasons: First, it is not the case that the existing system is perfect in every way with regard to incentives. Second, the new incentives feared under the ECAM, though perhaps present to some extent, are not likely to be very strong, nor is there any value to RMP from pursuing them. Third, if such issues are present, they can be addressed readily by new regulatory reporting and review, without any administrative difficulty.

Q. Please elaborate on each of these, beginning with how the existing system may include some incentives that are also not necessarily ideal.

A. The existing system involves reviewing all utility cost items concurrently at *ad hoc* intervals, and relying on occasional, possibly frequent, updates to fuel and power market forecasts in order to adjust rates (but not to true-up for any past over- or under-recovery of operating costs).

This no-ECAM approach implicitly encourages a utility to favor, utility-owned assets or fixed-cost supply contracts over resources and procurement strategies with more variable costs, even if the latter might be less expensive, on average. This incentive arises because the utility is exposed to risks from fuel and short term power costs that are quite volatile, difficult to forecast, and largely uncontrollable. There is less risk and more financial certainty from assets put into ratebase with an allowed return, compared to operating costs that must be forecasted, with inevitable variances from forecasts (often large, as was

[7] Direct Testimony of Michele Beck, p. 16 (lines 338-341).

demonstrated in section I of this rebuttal testimony).[8] [9] This bias towards lower risk assets that results from the lack of an ECAM is different than the bias sometimes noted for utilities of increasing the investment in rate-based assets. The former is just related to moving toward safer assets to avoid riskier fuel procurement while the latter is to increase earned returns.

In addition, the no true-up aspect of the current approach means that customers are at risk for paying amounts considerably different than actual costs. For the past several years, this has tended to occur in customers' favor, but there is no reason to believe that will be systematically true. Indeed, if it were systematically true, it would be evidence of a bias in the way forecasts are being made or set, which the utility should be entitled to correct.

Q. Why aren't the new, adverse incentives interveners are worried about under the ECAM likely to be very strong?

A. All that is really being alleged here is that the utility could become indifferent to the cost or risk of its fuel mix, not that it obtains a new, positive incentive to let costs rise or become more volatile. Since the utility will not enjoy any higher or different profits under the ECAM, regardless of whether fuel and power costs are high or low, there is no such positive incentive to let costs wander. This is just a fear of negligence creeping into utility operations, and that fear is totally

[8] If the utility is not earning an adequate return on equity, then there is also a disincentive to invest. This leaves the utility trying to choose the lesser of two fiduciary evils. This is very undesirable for its customers over the long run, because it means that resource adequacy and performance may become worse, and the utility is being forced to use decision criteria that are clearly not socially optimal.

[9] This is only true up to a certain point. Once a utility has enough owned assets that it is often a net seller of energy (or capacity), further fixed assets mostly bear spot market risk and so may not dampen overall volatility.

unfounded and naïve.

Utilities recover a significant part of their fixed, non-ECAM costs through variable charges. For instance, a typical residential customer pays a small monthly customer charge and buys the rest of its utility service on a cents per kWh basis, even though many of the transmission, distribution and administrative costs are fixed. Thus, a utility's financial health is dependent on the volume of power sold, regardless of whether it has an ECAM or not. At some point, increased commodity costs under the ECAM will start to reduce consumption, so the utility retains a strong incentive to keep operating costs under control in order to protect its other cost-recovery.

Even absent fixed costs in variable charges, utilities depend heavily on overall customer satisfaction in order to achieve reasonable regulatory allowances for all of their costs. If they were to become indifferent to the pattern of fuel costs, it would eventually hurt their credibility with customers and redound adversely to their interests in subsequent rate cases. Beyond this latent risk, there are many more short-term, explicit incentives and constraints in place that create pressure and rewards for controlling costs, including executive performance evaluations and oversight responsibilities, operating budgets set annually, regulatory reviews and comparisons to other utilities' plants and rates, and the like.

Q. If any such adverse incentives exist and are a material concern to regulators, can they be readily mitigated?

A. Yes, these problems, though likely to be quite small already, are readily blocked with simple and useful regulatory oversight of integrated resource planning (IRP), the ECAM costs and associated quality of service. Regulatory oversight of the IRP process should result in an optimal mix of long-term resources. Since operating costs are largely uncontrollable in-between times when the mix of fixed, long-term resources is altered (e.g., in an IRP process), the proper regulatory issue ought to be how the riskiness of these costs can be kept under control (not whether the costs should have been lower or higher on average). The efforts to control risk can be audited readily from reports on hedging practices (e.g, actual procurement vs. stated goals for hedging targets as to type, timing and quantities of hedges desired) and hedging success (as measured by forward-looking metrics of potential cost-risk staying within target ranges). These can be reported on as a routine aspect of ECAM filings providing assurance that no adverse choices are being made.

If there is a concern that RMP might be letting operating practices (such as maintenance) slide because any loss of efficiency (e.g., worse heat rates or availability) would just "flow through" the ECAM, then specific metrics of plant performance can be reviewed to see if they have slipped from historical or industry norms. Incentive terms can be created for these factors as well. It is very doubtful that that would prove necessary, but it would be simple to implement if needed.

Q. Are there advantages to going to the ECAM approach, above and beyond the improvement in cost recovery reliability for RMP and the accurate collection of true costs from customers?

A. Yes, the ECAM will replace the obsolete model of regulatory review and price-setting that RMP is operating under now. Virtually every state in the country has adopted a policy of recognizing that the process, time frames, and standards for regulatory scrutiny of operating costs are different than the process, time frames, and standards for review of long-term resource mix decisions. This results in a more efficient and effective regulatory process for both.

Instituting an ECAM will allow for this kind of clear separation between fuel procurement and asset mix decisions. The kinds of costs falling under the ECAM are largely uncontrollable between resource mix decisions, except insofar as they can be substantially but not completely hedged. Hedging involves analytic tools for forecasting and measuring <u>risk</u> over a few-year horizon, and these tools are very different from those used in finding least-cost, long term choices. The performance metrics for risk management are focused on how well the managers have adhered to risk targets and risk control guidelines. These goals can be reviewed periodically as an input to the ECAM process, and then the routine review process can focus on their attainment.

This separation allows a much more efficient attention to the more controllable decisions a utility can make about its long term resource mix, which can be addressed in IRPs and base rate cases rather than the ECAM proceedings.

IV. IMPLEMENTATION OF ECAM DOES NOT REQUIRE OR JUSTIFY A REDUCED COST OF CAPITAL

Q. Is cost of capital under an ECAM an appropriate concern for a Phase I review of whether the mechanism is in the public interest?

A. No, I do not believe it is. The economic issue in this case ought to be how the

NPC risks facing RMP have increased over time, how readily they can be controlled (or not) and how that risk affects its ongoing financial health and ease of providing high quality service. The cost of capital question would normally be debated in base rate cases, rather than fuel cost-recovery analyses. However, a few intervenors have suggested that there is or should be some direct relation between the ECAM and the cost of capital,[10] which I believe is incorrect for reasons I will explain briefly here.

Q. Why do you think there is no need to adjust, or even to plan to adjust, the cost of capital in conjunction with approving an ECAM?

A. Despite the fact that an ECAM changes the way fuel and short term power costs are collected, there is no theoretical or empirical basis for concluding that an adjustment to the cost of capital is required, or if it were, for estimating *a priori* how much of an adjustment would be relevant. It is possible that the ECAM could eventually yield the benefit of lowering the cost of capital (especially for the debt portion), but any adjustment should wait until that effect is actually observed in the financial market data.

Q. Isn't it true that the ECAM will reduce risk for PacifiCorp shareholders and therefore raise it for RMP customers?

A. No, that cannot be concluded. The existing system based on forecasted costs, when a large portion of costs is not hedgeable or readily forecasted with material accuracy, simply results in a large forecasting risk that is borne by both shareholders and ratepayers. (That is, the variance from forecast could favor

[10] Direct Testimony of Mr. Chernick, p. 34 (lines 813-816) and Direct Testimony of Mr. Chriss, p. 13 (lines 5-12).

either one of the two groups.) There is no reason to believe that the rates under an ECAM will be systematically higher or lower, or more or less variable over annual periods, than has been experienced in the past. They will simply be more accurate reflections of truly incurred costs. In that sense, an ECAM may involve less cash-flow variance for RMP, but this will not necessarily reduce RMP's costs of funds. In particular, it is unlikely that the cost of equity will decline, because the cost of equity reflects market-correlated, undiversifiable or "systematic" risk, which may not describe the changes in cash flows under an ECAM.

- The forecasting risk that is reduced or eliminated with an ECAM may not be systematic at all, as there is no reason (or evidence) to believe that these variances from forecasts tend to be high when financial markets are booming and low when they are soft.

- Fuel price risk by itself (ignoring volume uncertainties) may also not be systematic, or may not be systematic to the same extent over time: Sometimes, fuel prices rise in a booming market with a strong economy. However, sharply rising fuel prices can also cause the economy to slow down. Perhaps because of this complexity, none of the intervenors suggesting a cost of capital adjustment has an objective, rigorous theory of how much adjustment might be required, just an informal sense (or desire) for some kind of offset.

- The cost of equity is typically estimated from the returns earned or required by a group of similar, "proxy" firms – in this case other utilities. But in the U.S., essentially all of those utilities will already have an ECAM-like cost recovery mechanism for their fuel and purchased power costs, so any risk-reduction benefits that arise from such mechanisms is already in the proxy data.

Q. What about the cost of debt? Is it also unlikely to be affected by the ECAM?

A. It is more plausible that the cost of debt might fall, eventually, due to the ECAM, because the risk premium in debt (above the yield on government bonds of similar maturity and tax structure) is largely due to potential default risk, which in turn depends on total risk more than on systematic risk. The ECAM will reduce total risk to lenders, and so may result in lower borrowing rates. However, this will not affect the embedded cost of debt, only the future cost of additional debt. That effect can be rolled into rates if/when it happens.

V. CUSTOMER INVOLVEMENT ON HEDGING GOALS SHOULD NOT DELAY APPROVAL OF THE ECAM APPROACH.

Q. Witness Ms. Beck has suggested that the ECAM should be suspended until there can be more customer involvement in setting the goals and parameters of the hedging that the Company can pursue to manage risks. What role do you believe there is for such customer input?

A. It is certainly true that the hedging practices behind the ECAM should be designed with consideration of what types of risk are tolerable to customers. However, there is no reason to delay the ECAM for review of this question, for several reasons. First, customers do not yet have any experience with the pattern of costs that will come out of the ECAM as proposed, so they have no strong basis for saying what alternative pattern of risk exposure they might prefer. Second, it is likely that there is no universally acceptable or preferred pattern of NPC risk that will satisfy all or even most customers simultaneously. Third, there are limits and tradeoffs on how much risk can be reduced, and these may not yet be familiar to intervenors representing customers, nor to regulators. That familiarity will develop through review of the ECAM performance under existing hedging practices.

Thus it will take some time and experience with the ECAM before it is known whether the hedging risk goals should be revised to better match customer preferences. Meanwhile, there is no reason to believe that the existing hedging practices are not relevant or sufficient as a starting point. Once an ECAM is approved, the Phase II process of developing its implementation plan can include some discussion of what kinds of performance reports and benchmarks should be tracked. Over time, these can be used, along with customer reactions, to decide if the goals should be modified to pursue some other pattern of potential risk exposure.

Indeed, much of the way the ECAM risks ultimately will be felt by customers does not even depend on how the Company hedges its procurement, but on how it recovers the variances in rates over time. This is also a Phase II issue that can be discussed in concert with other policy questions, such as how much pricing efficiency is desired in the new structure.

VI. CONCLUSIONS

Q. Please summarize your rebuttal conclusions.

A. Accurate cost recovery for fuel and purchased power are critical to ensuring the financial health of any utility. This is especially true when the utility is embarking on a sustained capital expenditure program requiring significant cash flow for investment, in a tight credit market. (See the supplemental direct testimony of RMP witness Mr. Bruce Williams in regard to the planned expenditures.) The difficulty in accomplishing that with the existing approach in Utah has increased, and this situation is not amenable to fixing with better forecasting or hedging. There is large, but reasonable exposure to variances from the substantial amount of short term market balancing that is required to serve loads with the PacifiCorp resources. These difficulties are likely to increase in the future, as more and more nonstandard (renewable) resources are added to the system and the regional grid, and as climate policy constraints become part of the power market environment. Thus, it is timely to introduce an ECAM now, and to tune it up over time after a meaningful history of performance reporting is in hand.

In general, it is harder to restore financial credibility than to preserve it. An ECAM can help preserve financial health for RMP and PacifiCorp, thereby making its future capital requirements for system maintenance and improvements easier to achieve at reasonable financial cost. This will benefit customers, as will having a cost recovery mechanism that reliably recovers only the actual operating costs of RMP. The ECAM process will also prove to be a regulatory benefit, efficiently separating the review of non-controllable operating costs from longer term resource and risk-measurement

Q. Does this conclude your testimony?

A. Yes it does.