Q. Please state your name, business address and present position with Rocky Mountain Power, a division of PacifiCorp (the Company).

A. My name is Gregory N. Duvall, my business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232, and my present title is Director, Long Range Planning and Net Power Costs.

Q. Have you previously filed testimony in this case?

A. Yes. I filed Direct Testimony in this case.

Q. Will any other witnesses be presenting Supplemental Direct Testimony with this filing?

A. Yes. In addition to myself, three additional witnesses will present Supplemental Direct Testimony in support of Rocky Mountain Power's[1] Energy Cost Adjustment Mechanism (ECAM): Dr. Karl A. McDermott, Ameren Distinguished Professor of Business and Government at the University of Illinois at Springfield and a Special Consultant to National Economic Research Associates, Inc. ("NERA"), Mr. Frank C. Graves, Principal at The Brattle Group, and Mr. Bruce N. Williams, Vice President and Treasurer of PacifiCorp,

Q. What is the purpose of the Company's supplemental filing?

A. The supplemental filing responds to issues raised in the Commission's June 18, 2009 Procedural Order in this docket in which the Commission directed:

> At a minimum, we note the following issues should be examined: 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

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

> 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.

The supplemental filing also addresses issues raised by parties in their comments filed in this docket.

I address the first issue raised by the Commission, an explicit and quantitative analysis of the risks of fluctuating power costs including the magnitude and nature of the risks. I also address how the magnitude of those risks has changed since the Energy Balancing Account (EBA) was terminated in 1992.

Dr. McDermott provides testimony on all of the issues in the Commission's procedural order. He provides a review of the public interest aspects of adopting an ECAM both generically, and specifically as it applies to Rocky Mountain Power's proposal.

Mr. Graves also provides an analysis of the risk of fluctuating power costs and the alternatives available to manage these risks. He presents an evaluation of the risk management capabilities and practices of the Company to determine how they can contribute to managing the cost and quantity risks that will be recovered in the ECAM. He also reviews some of the basic principles of risk measurement and management, and explains the practical limitations and tradeoffs involved in hedging to reduce power supply risks.

Mr. Williams explains why the absence of a fuel and purchased power adjustment mechanism such as the Company's proposed Energy Cost Adjustment Mechanism, increases the risk to earnings and cash flow caused by volatility in net power costs. He discusses why and how this volatility can adversely impact the Company's access to capital and liquidity, to the detriment of the Company and its customers.

Summary of Testimony

Q. Will you please summarize the topics you will cover in your Supplemental Direct Testimony?

A. In my Supplemental Direct Testimony, I present the following:

- An overall discussion and quantification of the Company's actual net power costs ("NPC") versus what has been and is now included in rates over the past 19 years;
- Analytic evidence that demonstrates significant variations in NPC related to factors outside of the Company's control;
- A quantification of load forecast error due to weather and uncertain economic conditions; and
- A comparison of various sources of fuel in NPC over time showing the increasing reliance on natural gas and other sources with high price volatility.

Summary of the Company's Track Record of Accurately Reflecting NPC in Rates Since Elimination of the Energy Balancing Account

Q. How important is it to accurately reflect NPC in Utah customer's rates?

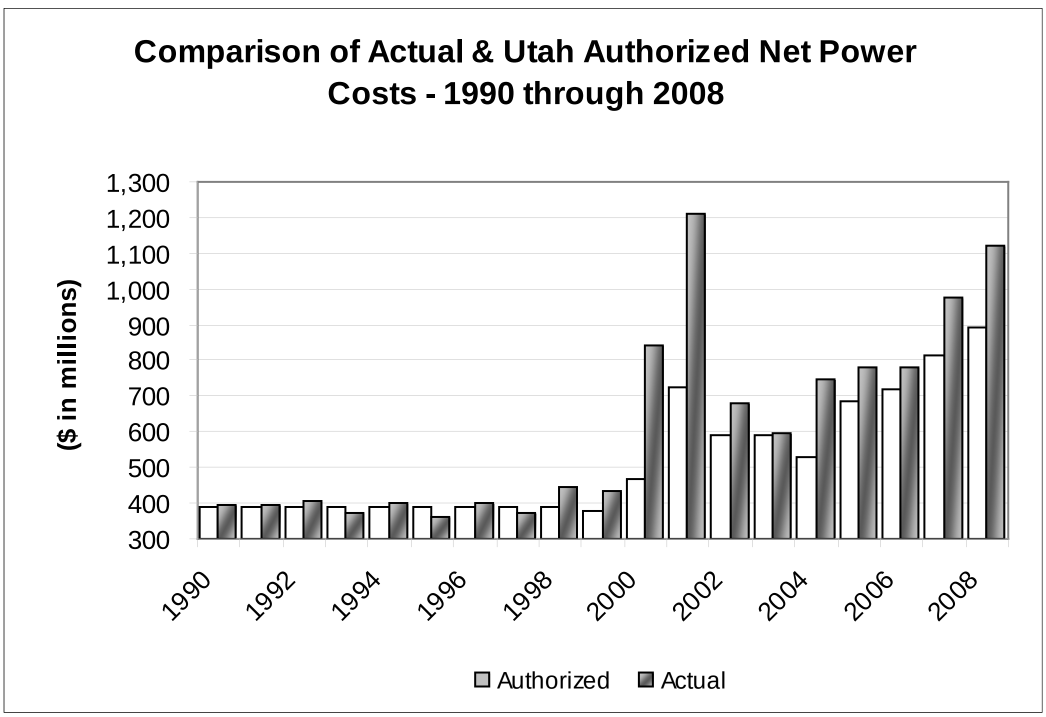
A. NPC represent the single largest component of revenue requirement. NPC accounted for nearly one-third of the total revenue requirement increase proposed in recent rate cases in Utah. To the extent these costs are not accurately reflected in rates, customers do not see the true cost of serving them in their prices, the

Company does not recover its prudent costs of serving customers, and the public interest is not well served.

Q. Please provide a detailed analysis of the Company's actual NPC versus what was recovered in Utah rates over the last 19 years.

A. Table 1 shows the actual NPC that the Company has incurred over the last 19 years compared to the NPC which have been included in rates in this jurisdiction. When a case settled without expressly stating the system NPC baseline, the Company assumed that system NPC in rates is what was reflected in the Company's filing.

Table 1 – Comparison of Actual and Utah Authorized Net Power Costs



Q. Please describe the results shown in Table 1.

A. Table 1 shows that the Company has consistently spent more on net power costs to serve its customers than it has recovered in rates. However, the trend and magnitude of this situation in recent years is the most significant aspect of this Table. The historical recoveries from 1990–1999 had some years of under- and over-recovery but the total dollar amounts were generally fairly small. In 2000–2001, the large under recovery is explained in part by the power crisis (and was partly offset by deferred accounts for power costs and collection through a surcharge). But in 2002–2007, the amount of NPC included in the Company's rates consistently has been below its actual costs, in every year by a wide margin. In fact, the differences in 2007 and 2008 are in excess of $160 million and $230 million, respectively.

Q. What is your general observation about what has caused the Company's authorized NPC to differ so significantly from actual NPC?

A. 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.

Effect of Hedging

Q. Can the Company eliminate the risks of uncertainty and volatility using hedging instruments?

A. No. Hedging activities can reduce the range of potential outcomes but significant uncertainty and volatility remains inherent in NPC. In fact 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, but actual NPC were substantially different than projected NPC as discussed above. 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, but 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. This subject is explored in greater depth in Mr. Graves' Supplemental Direct Testimony.

Q. Can you give some examples of these events?

A. Yes. Normalized NPC, which are used today, rely on loads that are forecast using "normal" temperatures. However, actual temperatures can vary significantly from normal, causing changes in load of a few megawatts ("MW") to hundreds of MW in an hour. These variations are not more accurately estimated until realistic weather forecasts are made, or about a week before loads actually occur, rendering it impossible for the Company to hedge perfectly a year in advance.

Q. Are there other reasons the actual load can vary significantly from forecast?

A. Yes. The load is sensitive to economic variables, oil price, and natural gas price. In the current economy, as national, state, and county level economic variables fluctuate with nationwide volatile economic conditions, load can change from forecast significantly in either direction. Industrial loads in particular are sensitive to oil and gas prices and changes in the housing market. Residential and commercial loads are also subject to changes in the economy and irrigation loads can vary significantly with changes in rainfall and temperature.

Q. Do you have any examples to quantify the variation between actual and forecast loads?

A. Yes. System-wide loads under normal temperatures for January 27, 2009, were predicted as of November 2008 to be 8,010 MW; however due to the cold temperatures across the Company's service territories, the actual load was 8,524 MW—an uncontrollable increase in loads of 514 MW. On the contrary, in February, the picture was quite different since it was a milder month. On February 7, 2009, actual loads were 524 MW below expectation. When either of these situations occurs, the system operators have to buy or sell power at prevailing market prices. These transactions cannot be hedged ahead of time, and in addition will result in transaction costs associated with the bid/ask spread.

Q. Do generating resources suffer from the same issues of uncertainty and volatility?

A. Yes. The output of hydro, thermal and wind resources are all unpredictable. One thing the Company knows for sure is that the actual output will not be what was forecast at the time of general rate case filing. This is true on a year-ahead, month-ahead, day-ahead and hour-ahead basis. Each time better information is available about the expected output of these resources, the Company must balance its position by buying or selling into the market. These are transactions that cannot be known and therefore cannot be perfectly hedged ahead of time.

Q. Have you quantified how these uncertainties affect NPC?

A. Yes. In addition to the quantification provided above comparing the difference between actual and normalized NPC over the past 19 years, I have conducted a study to determine the stochastic risk of loads, forced outages, and hydro generation. This study used the 2008 IRP preferred portfolio and the Company's stochastic production cost simulation model, called Planning and Risk. In this sensitivity study, I produced a model run where loads, forced outages, and hydro generation were not subjected to Monte Carlo random draws. This run simulated the case where the Company fully and perfectly hedges the risk associated with these stochastic variables. I then compared the resulting stochastic portfolio cost with that of the base run where all stochastic variables—including forward electricity and commodity natural gas—are subjected to Monte Carlo random draws. The cost difference between the two runs reflects the stochastic risk associated only with loads, forced outages, and hydro generation.

Q. What is the result of your analysis?

A. Using 2012 as the study year, I found that portfolio stochastic cost, as measured by the average of 100 Monte Carlo simulation outcomes, increased by $80 million due solely to the combined volatility of loads, forced outages, and hydro generation. Tail risk, which is defined for this sensitivity study as the average of the five highest-cost simulation outcomes, increased by $666 million. This study demonstrates that there are significant amounts of NPC that cannot be controlled using hedges.

Q. Does this account for the variability of wind resources?

A. No. Wind variability is not modeled as a stochastic variable in the Company's Planning and Risk model. However, the impact of wind variability on the Company's incremental cost to balance generation and loads has been quantified and reported as an incremental wind integration cost in Appendix F in Volume II of PacifiCorp's 2008 IRP.

Change in Fuel Sources

Q. How have the Company's fuel sources changed since the early 1990s?

A. Table 2 below shows the change in fuel source[2] from 1992[3] to 2009.

Table 2 – Capacity Resource Mix from 1992 to 2009 (megawatts)

	1992		2009	
Resource Type	**MW**	**% of Total**	**MW**	**% of Total**
Coal	6,466	66%	6,128	43%
Purchased Power & Other	1,869	19%	2,570	18%
Hydro	1,290	13%	1,450	10%
Gas	110	1%	2,406	17%
Nuclear	27	0%	-	0%
Geothermal & Other Renewables	21	0%	34	0%
Wind	-	0%	1,372	10%
DSM	-	0%	345	2%
Total (MW)	**9,783**	**100% [4]**	**14,304**	**100%**

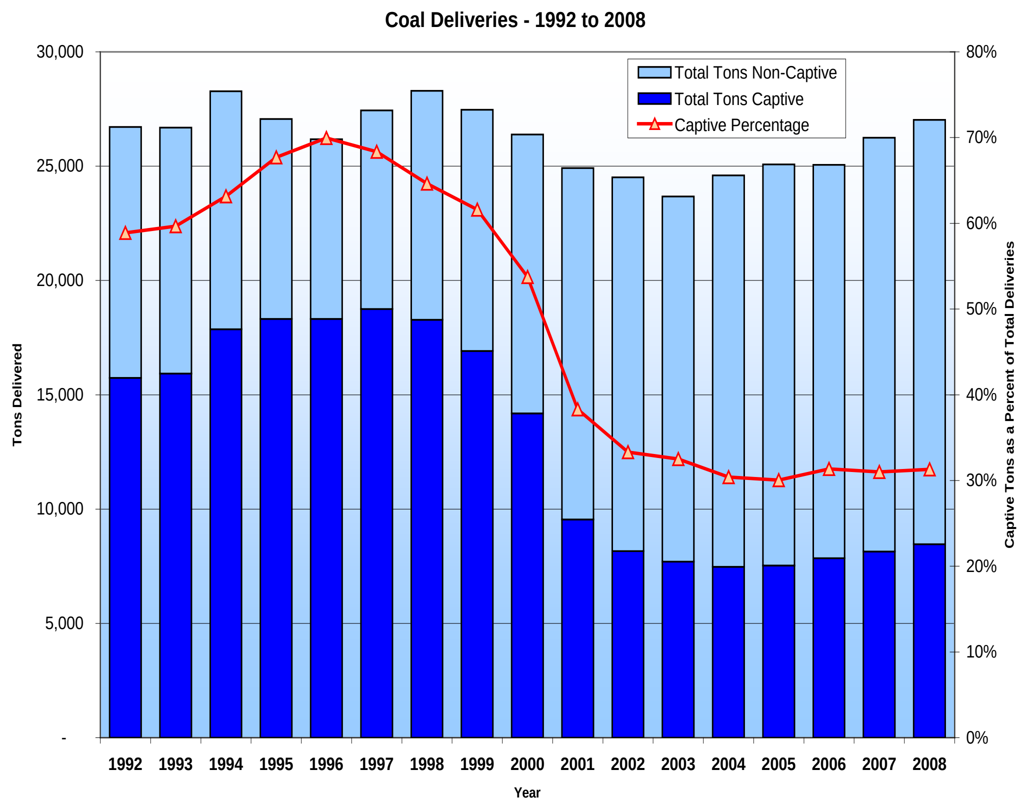
In addition, Table 3 shows how the source of coal has changed over time.

[2] For comparability purposes only, wind resources are shown at nameplate capacity versus capacity contribution at peak.

[3] Source: Balanced Planning for Growth, Resource and Market Planning Program ("RAMPP2"), May 14, 1992, page 33, Table 3-3.

[4] Does not add to 100 percent due to rounding.

Table 3 – Coal Deliveries from Captive Coal Mines (1992-2008)



Q. What do you observe from this data?

A. In 1992, the Company's resource portfolio capacity was 66 percent coal, 19 percent long-term purchased power contracts (over half of which was a capacity contract with the Bonneville Power Administration), 13 percent hydro, and the remaining 2 percent made up of a small amount of natural gas, geothermal and nuclear generation. Notably absent was any wind or any significant natural gas fired resources.

In contrast to this, the Company has increased its reliance on wind by 10 percent and natural gas-fired resources by 16 percent between 1992 and 2009, while concurrently reducing its reliance on coal plants from 66 percent to 43 percent. Over the same time period, the percentage of coal supplied from captive mines has decreased from about 60 percent to just over 30 percent. The Company's resource portfolio now includes about 2,400 MW of natural gas-fired resource and nearly 1,400 MW of installed wind capacity.

Q. What do you conclude from the foregoing?

A. The change in the Company's portfolio mix described above is a result of the need to meet growing customer loads, replace expiring purchased power agreements, meet renewable energy requirements and ensure the Company has enough flexible resources to provide reliable service to customers. Given current energy policies that place an increasing importance on carbon regulation and renewable resources, the Company believes the trend of moving toward a more volatile portfolio, as has been the case over the past 17 years, is necessary and is likely to continue well into the future. Based on the evidence presented here and in my Direct Testimony, along with the supplemental testimony presented by Dr. McDermott, Mr. Graves and Mr. Williams, the Company believes the public interest is best served by implementing the Company proposed ECAM in Utah from today and into the future.

Q. Does this conclude your testimony?

A. Yes.