BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.	**Docket No. 09-035-23**

Direct Testimony and Exhibits of

Maurice Brubaker

Phase I

On behalf of

Utah Industrial Energy Consumers

October 8, 2009

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 9168

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Direct Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and president of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Utah Industrial Energy Consumers (UIEC). Members of UIEC purchase substantial quantities of electricity from Rocky Mountain Power Company (RMP) in Utah, and are vitally interested in the outcome of this proceeding.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q WHAT SUBJECTS ARE ADDRESSED IN YOUR TESTIMONY?

A I address certain issues with respect to class cost of service and revenue allocation. My cost of service and revenue allocation testimony is directed to RMP's embedded class cost of service study and its proposed distribution of any awarded rate increase.

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations may be summarized as follows:

1. RMP uses load research sample data to estimate the loads of several of its major classes, including Schedule 1 (Residential), Schedule 6 (Large General Service) and Schedule 23 (Small General Service).

2. The load research samples for these three classes are very old. The Schedule 6 and Schedule 23 samples were installed in 1990, and the Residential sample was installed in 1991.

3. RMP's ancient load research samples have not been shown to be representative of RMP's current customers in Utah, because many changes have taken place in the use of appliances (particularly central air conditioning) and in load shapes.

4. The loads used in RMP's class cost of service study are not reconciled to the loads in the jurisdictional study. The sums of the class loads at the times of the monthly system peaks in the class study are considerably smaller than the loads in the jurisdictional study used to allocate costs to Utah. As a result, costs are over-allocated to customer classes with 100% metered loads, like Schedules 8 and 9.

5. Given the age of the load research samples, the mismatch in the class and jurisdictional class cost of service study loads, the other problems I note and the general lack of reliability of RMP's cost of service studies, they should not be used in distributing rate adjustments in this proceeding.

6. RMP cannot have a reliable class cost of service study until such time as the results of the new load research sample have been in place for a period of at least 12 months, plus the time required to analyze the results and convert them into class loads for use in a class cost of service study.

7. Any adjustment in rates applicable to RMP in this case should be applied as an equal percentage change across the board.

8. The system and jurisdictional load shape support a summer coincident peak allocation, not RMP's 12CP allocation.

9. RMP's 75% weighting to demand and 25% weighting to energy for the allocation of generation and transmission fixed costs is equivalent to classifying 25% of fixed costs as energy-related and allocating those costs to customer classes using an energy allocation factor. This approach is inappropriate and should be disregarded in favor of classifying and allocating all fixed costs associated with generation and transmission on a demand basis.

10. RMP's current cost allocation methodology does not adequately capture the costs associated with the very large peaking requirements imposed on the system by residential and Schedule 6 customers. A summer peak allocation method would come closer to properly reflecting these costs.

11. Further refinements of the treatment of variable costs in the cost of service study should be analyzed and implemented after the Commission has made its determination with respect to an Energy Cost Adjustment Mechanism. It is not possible to make the appropriate adjustments until determinations about the fundamental nature of the Energy Cost Adjustment Mechanism, if any, have been made. These adjustments can take place in a general rate case following such determinations with respect to an Energy Cost Adjustment Mechanism.

12. There is a significant difference (over $50 million per year) between the revenue requirement for transmission that RMP asks for in this case from Utah customers, and the revenue requirement associated with Utah retail transmission service which is contained in PacifiCorp's 2009 update of its Open Access Transmission Tariff at FERC. If RMP cannot rationalize this difference, then the lower FERC revenue requirement should be used in this case.

13. RMP does not appear to be using any option type of instruments to provide the opportunity to benefit from declines in the market price of natural gas. RMP should explain why it has not used such options, or if it has considered but rejected them, it should also explain that reasoning.

EMBEDDED CLASS COST OF SERVICE ISSUES

Q HAVE YOU REVIEWED THE DEVELOPMENT OF RMP'S EMBEDDED CLASS COST OF SERVICE STUDY?

A Yes. I have reviewed the allocations, and some of the key input information, particularly the customer class loads.

Purpose of Cost of Service Studies

Q BEFORE ADDRESSING THE PARTICULAR COST OF SERVICE ISSUES IN THIS CASE, PLEASE DISCUSS THE PURPOSE OF PERFORMING COST OF SERVICE ANALYSES.

A Cost of service analyses are performed for the purpose of developing the most reasonable estimate of the cost of providing utility services to individual rate classes, rate schedules and customers. Basing rates on costs, using the most accurate available measures of cost-causation, is a well established and long endorsed principle in establishing utility rates.

While no cost of service study can be taken as 100% correct, or 100% accurate as to measurement, reasonable efforts can and should be undertaken to develop customer, rate schedule and class load data that is reasonably accurate, and can confidently be used in developing class and rate schedule rates of return, and rates that appropriately charge the customers taking service on each tariff.

RMP's Class Load Data is Not Reliable

Q BY WAY OF SUMMARY, AFTER YOUR REVIEW OF RMP'S COST OF SERVICE STUDIES, DO YOU BELIEVE THAT THEY ARE SUFFICIENTLY ACCURATE AND REPRESENTATIVE FOR USE IN SETTING REVENUE REQUIREMENTS FOR CLASSES AND RATE SCHEDULES AND FOR DESIGNING RATES?

A No, I do not. As I will discuss subsequently, the load data estimates for rate schedules that are not demand-metered are based almost entirely on ancient samples and the end result of RMP's load research and load development clearly demonstrates that there is a material inaccuracy. This inaccuracy manifests itself through the substantial difference between the "top-down" jurisdictional loads used for allocation between states and the "bottom-up" summation of the individual customer class loads used in the class cost of service study.

In addition, RMP's cost of service analysis does not provide a separation or breakout of a number of the rate schedules that are lumped together for purposes of the class cost of service study. For example, the Residential class consists of Schedules 1, 2 and 3. RMP's study lumps them together for cost analysis purposes, so no conclusions can be reached about the appropriate pricing of any of them. A similar problem exists with respect to rate Schedules 9 and 9A where the loads are combined for class cost of service purposes and there is no separation of the commercial, industrial and public authority customers served on the rate. This lack of articulation by rate schedule and customer type makes the cost of service studies less useful for establishing revenue requirements for individual tariffs and for designing appropriate rate structures.

Q WHAT TEST YEAR DOES RMP USE FOR THE CLASS COST OF SERVICE STUDY?

A It uses the same test year that it uses for the jurisdictional allocation study and the revenue requirement test year, namely the estimated 12 months ending June 2010.

Q DOES THE USE OF ESTIMATES FOR A FUTURE TIME PERIOD IMPACT THE CLASS COST OF SERVICE STUDY?

A Yes. In general, it impacts the class cost of service study because all of the class load data that is used for the allocations had to be estimated based upon a prior actual time period. In this instance, RMP used the 12 months ended December 31, 2008 as the base line or starting point, and adjusted class loads and other input data to a forecast for the 12 months ending June 2010. Thus, problems similar to what are introduced into the revenue requirement determination, including an accurate inter-jurisdictional allocation, are present in the class cost of service study as well.

Q NOTWITHSTANDING THE ESTIMATED NATURE OF ALL OF THE INFORMATION, ARE THERE PARTICULAR FACTORS APPLICABLE TO RMP'S CLASS COST OF SERVICE STUDY THAT CAUSE YOU CONCERN ABOUT ITS ACCURACY?

A Yes. While for some of the major customer classes, including Schedules 8 and 9 and contract customers, RMP has demand metering and can determine accurately the hourly loads of these customer classes, it must rely upon load research samples to estimate the loads of other major customer classes.

Q FOR WHICH CUSTOMER CLASSES DOES RMP RELY UPON LOAD RESEARCH SAMPLE DATA?

A RMP relies upon load research sample data for Residential Schedule 1, Large General Service Schedule 6 and Small General Service Schedule 23.

Q WHAT DOES IT MEAN TO RELY UPON LOAD RESEARCH SAMPLE DATA AS CONTRASTED TO HAVING COMPREHENSIVE AND ACCURATE DEMAND METERING FOR BILLING PURPOSES ON EACH CUSTOMER?

A When a load research sample is used it means that the utility must construct a small sample, thought to be representative, of the population of each customer class. Load research meters are placed on a few selected customers and the results of the load research are then expanded to estimate the hourly loads, including contributions to monthly system peaks, of the entire class.

Q IS THE USE OF LOAD RESEARCH SAMPLING FOR CUSTOMERS SUCH AS THOSE ON SCHEDULES 1, 6 AND 23 A FAIRLY COMMON PRACTICE IN THE ELECTRIC UTILITY INDUSTRY?

A Yes, it is.

Q WHAT, THEN, IS THE ISSUE?

A The basic issue is the age of the load research samples, and the resulting question as to whether the sample data continues to be representative of these classes as they exist today.

Q WHEN WERE THE LOAD RESEARCH SAMPLES FOR THESE CLASSES FIRST DESIGNED AND IMPLEMENTED?

A This information is provided in response to UIEC Data Request No. 2.1. As stated by RMP in that response, the Residential sample was originally installed in 1991. It was supplemented with additional sites in 1999, but the original sample apparently was not redrawn, and the initial sample group was not replaced.

The Schedule 6 sample was installed in 1990, and apparently was not updated or supplemented.

The Schedule 23 sample was installed in 1990, and also apparently was not supplemented or updated.

Q HASN'T RMP RECENTLY DEVELOPED NEW LOAD SAMPLES FOR CUSTOMERS ON SCHEDULES 1, 6 AND 23?

A Yes. RMP recently developed those samples. In response to UIEC Data Request No. 2.6, RMP reported that in this case it has used the results of these new samples for three winter months of data for Schedules 1 and 23, and two winter months for Schedule 6. Thus, none of this data for most of the months, including the critical summer months, is from the new sample.

Q ARE THE LOADS OF ANY OTHER MAJOR CLASSES DEVELOPED BASED ON LOAD RESEARCH SAMPLES?

A Yes. The load data for Irrigation Schedule 10 is based on load research, but a new sample was installed prior to the 2007 irrigation season, and thus is relatively current.

Q HAVE THE NATURE OF THE SYSTEM LOAD, AND CUSTOMER USAGE PATTERNS, CHANGED MATERIALLY SINCE THESE LOAD RESEARCH SAMPLES WERE INSTALLED?

A Yes, materially. For example, in Docket 07-035-93, RMP witness Dr. Rife noted at page 14 of his testimony (beginning at line 313):

> "Prior to 1999, the system as a whole peaked during the winter months. Because of the growth in Utah, the Company has started to experience summer peaks and expects this pattern to continue in the future. This is evident in Utah state growth rates. From 2002 through 2006, while the energy growth in Utah averaged 3.2 percent per year, the summer peak average growth rate was 3.4 percent."

Q DID DR. RIFE EXPLAIN WHY THE SUMMER PEAK LOADS ARE GROWING IN RELATION TO LOADS IN OTHER MONTHS?

A Yes. He discussed this at some length beginning on page 13 of the referenced testimony. Beginning at line 294, he observed as follows:

> "During the last decade, Utah homes on average have increased in size. As the growth continues, the Company expects the average size of homes to further increase. Additionally, the Company is seeing more homes that have Central Air Conditioners (CAC). Customers across our Utah service territory are seeking more comfortable living conditions and seem to be willing to pay for them. CAC are becoming the norm for space conditioning on hot summer days. More new homes require CAC as a selling point. Customers with Evaporative Air Conditioners (EAC) are changing their equipment to keep up with the norm."

Q WHAT ARE THE IMPLICATIONS OF THESE CHANGES IN RESIDENTIAL LOAD AS THEY IMPACT THE LOAD RESEARCH SAMPLE DATA AND ITS CONTINUED APPLICABILITY?

A The fact that the character and nature of the Residential class load has changed so dramatically over the last nearly two decades since the initial sample was installed calls into question whether the sample as originally drawn continues to be representative of the usage patterns of the Residential customers in Utah today. Clearly, many of the customers who exist today and who live in newer homes, most of which apparently have central air conditioning, were not on the system at the time that the initial sample was drawn.

This would suggest a strong possibility that the existing Residential load research sample data is not representative of today's Residential customer class. Similar comparisons can be made for Schedule 6 and Schedule 23 customers.

The combination of two or three months of new sample data with eight or nine months of old sample data doesn't make the result any more accurate.

Q HOW HAS RESIDENTIAL USE PER CUSTOMER CHANGED OVER TIME, AND HOW DOES THAT AFFECT THE VALIDITY OF THE SAMPLES?

A Dr. Rife's Exhibit GMR-5 in Docket No. 07-035-93 showed some of this information back to 1996. This exhibit showed per kilowatthour Residential customer usage for the summer and winter periods from 1996 through 2006 and as then forecasted for 2007 through 2009.

Summer usage in 1996 for the average Residential customer was 646 kWh per month, and in 2006 it was 823 kWh per month, a growth of about 27%. The forecast for 2007 through 2009 is in the range of 924 kWh per month to 939 kWh per month. The estimated average for these three years is 933 kWh per summer month, which represents an increase of about 44% from 1996 for Residential customers.

In contrast, the winter average usage for Residential customers has grown only modestly. From a starting value of 665 kWh per average winter month in 1996 (which was then higher than the summer average usage), it grew to 693 kWh per month in 2006, an overall growth of 4.2%. The average projected for 2007 through 2009 for winter Residential average kilowatthour use was 701 kWh per month, a total growth of only 5.4% since 1996.

This dramatic change in the concentration of energy usage in summer months that is quite apparent today, as contrasted to the circumstances when the original samples were drawn, further underscores the antiquated and unreliable nature of the Residential load research data that RMP uses in its class cost of service study. Obviously, given this material change in load patterns of the Residential (and probably also Commercial) customers, the study results should not be relied upon.

It also is important to recognize that RMP has subsequently implemented an inverted summer Residential rate. The effect that this rate change has had on

Residential load profiles must be examined in order to have accurate information about Residential hourly loads. For example, it would be important to learn whether, in response to the inverted rate that charges more as total monthly usage increases, customers run their air conditioners less on moderate days, but still use them the same as always when temperatures reach the highest levels – thereby “sharpening” the peaks – the “needle peak” problem that was discussed extensively in earlier cases.

RMP Has Not Properly Adjusted Class Loads for Temperature

Q YOU HAVE PREVIOUSLY REFERRED TO THE IMPACT OF WEATHER ON SYSTEM LOADS AND SYSTEM LOAD SHAPE. IS WEATHER AN IMPORTANT DETERMINANT OF CLASS LOADS AS WELL?

A Yes. Class loads, of course, drive the system peak load. The hourly loads, and particularly those of the Utah residential and commercial customers, are heavily influenced by weather conditions. In fact, according to the response to UIEC Data Request No. 2.34, the average kW per customer for Utah residential customers on peak summer days has increased more than 25% from 1996 to 2008.

Q IN DEVELOPING CLASS LOADS FOR PURPOSES OF THE CLASS COST OF SERVICE STUDY, HOW DOES RMP TAKE PEAK TEMPERATURE INTO ACCOUNT?

A This is perhaps best explained by UIEC's Data Request No. 2.14, and RMP's response:

> **UIEC Data Request 2.14**
> “Is the customer load data in this case calculated from forecasted energy data that is weather normalized? If so, please explain whether the weather normalization of energy is based on “average”

> temperatures or "peak-making" temperatures. Please explain the impact of using average versus peak-making temperatures."
>
> **Response to UIEC Data Request 2.14**
> "The customer load data is not calculated from forecasted energy data. Rather, the historical load data is adjusted to forecasted energy. The forecasted energy data reflects normal weather conditions. The normal weather is based on the 20-year <u>average monthly temperatures</u>. It is not possible to apply monthly "peak-making" temperatures (which is the temperature for a peak hour) to forecast monthly energy." [Emphasis added.]

Q CAN YOU ILLUSTRATE THE NATURE OF THE PROBLEM?

A As noted, the adjustment to energy is made on the basis of average monthly temperatures. Suppose that the adjustment based on average monthly temperature differences would require a 3% increase in monthly kilowatthours. Assume further that the "peak hour" temperature difference would require a 10% increase in the hourly demand to match the sample data to true "peak making" weather. RMP would make the 3% adjustment across-the-board, not the 10% adjustment, thereby understating the demands at the time of the peak.

Q WHAT DOES THIS MEAN IN TERMS OF THE APPROPRIATENESS OF RMP'S WEATHER ADJUSTMENT?

A It means that RMP's weather adjustment is completely inadequate to capture the impact of peak making "temperatures." While RMP says that it is "not possible" to develop loads on this basis, it would be more appropriate simply to say that RMP has chosen not to attempt to make adjustments on this basis.

<u>Class Loads Don't Equal Jurisdictional Loads</u>

Q RETURNING TO A POINT YOU MADE EARLIER CONCERNING THE QUALITY OF RMP'S LOAD RESEARCH DATA, DO YOU HAVE ANY ANALYTICAL DATA TO SHOW HOW THIS MANIFESTS ITSELF IN THE CLASS COST OF SERVICE STUDY?

A Yes. The serious nature of the problem can be appreciated by looking at the difference between the estimated jurisdictional total loads (used to allocate costs between states) and the class loads which RMP uses in its class cost of service study to apportion the costs allocated to Utah among the Utah customer classes.

Q CAN YOU ILLUSTRATE THE DIFFERENCE BETWEEN THE CONTRIBUTION TO THE OVERALL SYSTEM PEAKS BY THE UTAH JURISDICTION THAT IS USED IN THE JURISDICTIONAL COST OF SERVICE STUDY FOR REVENUE REQUIREMENT PURPOSES, AND THE CONTRIBUTIONS TO THOSE SAME PEAKS THAT ARE USED IN THE CLASS COST OF SERVICE STUDY?

A Yes. This is shown on Exhibit UIEC ____ (MEB-1). Page 1 of this exhibit shows in graphical format the contributions to peaks used in the jurisdictional allocation study as compared to the sum of the individual class contributions to those same peaks used in the class cost of service study. Page 2 of the exhibit shows the information in tabular format, and also illustrates the differences graphically.

Q WHAT DOES THIS EXHIBIT DEMONSTRATE?

A It clearly shows that there are major differences between: (1) the "bottom-up" sum of the load research study data for classes such as Schedules 1, 6, 10 and 23 and the metered data for other classes in the class cost of service study and (2) the "top-down" determination of the contribution of Utah loads in the aggregate to the monthly system peaks.

Referring to page 2 of Exhibit UIEC ____ (MEB-1), note that the loads from the class cost of service study are lower than the loads from the jurisdictional study in all but two months. In the four highest load months, the total of the class loads from the class cost of service study range between 400 megawatts and 800 megawatts below the level of the load reported in the jurisdictional study. This is a range of between 10% and almost 21% below the jurisdictional total. And, since the classes whose loads are determined from load research do not represent the entire load, the error as a percentage of just those class loads is even worse.

In general, the class load research data produce lower contributions to the peaks than does the "top-down" determination of jurisdictional peaks used in the jurisdictional allocation study.

Q WHAT DOES THIS MEAN?

A It could mean several things. If the "top-down" study used for jurisdictional allocation purposes is incorrect and the class studies are correct, it means that too much cost is being allocated to Utah.

If the determination of the contribution to system peak by jurisdiction used in the jurisdictional cost allocation study is correct, it means that the load research and other analysis conducted by RMP to develop the loads used in its class cost of service study are inaccurate. As a result, when RMP combines the understated loads of these classes that are sampled with the 100% metered loads of the larger customers (such as those on Schedules 8 and 9) and uses this for allocation, the amount of costs allocated to classes such as Schedules 8 and 9 is overstated. This understates their rate of return, and overstates the apparent increases required to reach cost of service.

Q IN THE PAST, RMP HAS ARGUED THAT THESE DIFFERENCES MAY BE PARTLY ATTRIBUTABLE TO IMPRECISION IN THE MEASUREMENT OF OR DETERMINATION OF DEMAND LOSSES, AND/OR IN THE MEASUREMENT OR ATTRIBUTION OF CERTAIN RESALE OR WHOLESALE LOADS. DO YOU BELIEVE THAT THOSE FACTORS COULD ACCOUNT FOR THIS LARGE DIFFERENCE?

A I believe that these differences are far too large to be accounted for by those factors.

Q HAS RMP MADE ANY EFFORT TO UNDERSTAND, EXPLAIN OR RECONCILE THE DIFFERENCES BETWEEN THE TOP-DOWN JURISDICTIONAL LOADS AND THE "BOTTOM-UP" LOADS?

A Surprisingly, no. UIEC Data Request No. 4.2 asked:

> **UIEC Data Request 4.2**
> "Please provide all analyses that have been conducted by or for Rocky Mountain Power Company over the last five years in an attempt to understand, explain and reconcile the difference between the "top-down" jurisdictional loads at the time of the 12 monthly system peaks as compared to the "bottom-up" summation of the demands of each of the retail rate classes at the time of those same 12 monthly peaks."

In response to this data request, RMP answered as follows:

> **Response to UIEC Data Request 4.2**
> "Over the last five years, the Company has not conducted, nor has it contracted to be conducted, any studies to understand, explain or reconcile the difference between the "top-down" jurisdictional loads at the time of the 12 monthly system peaks as compared to the "bottom-up" summation of the demands of each of the retail rate classes at the time of those same 12 monthly peaks."

Obviously, RMP has no explanation.

The Disparity Has Grown Enormously

Q HAVE THE DIFFERENCES THAT ARE EVIDENT IN THIS TEST YEAR BEEN AS LARGE IN PRIOR YEARS?

A No. The differences have been growing over time.

Q CAN YOU ILLUSTRATE?

A Yes, I can. Exhibit UIEC ____ (MEB-2), consisting of six pages, presents a comparison of the bottom-up and top-down load data from RMP's six prior rate cases in Utah. A quick review of this information shows that the disparity between the two has been growing significantly over time.

Note from page 1 of Exhibit UIEC ____ (MEB-2), that for the 12 months ended September 2000 used in Docket No. 01-035-01, the deviations were relatively small. Most of the deviations were less than 2%, with the maximum deviation being 7%. As you flip through the various pages of this exhibit, note how the differences continue to grow, and how the differences in the summer months grow even faster than the differences in other months. A comparison of page 1 of Exhibit UIEC ____ (MEB-2), with page 2 of Exhibit UIEC ____ (MEB-1), puts the growth in disparity in perspective. As measured by the average monthly deviation between the jurisdictional and class numbers (line 13 of column 3 in the tables), the deviations in the current test year are 18 times the deviations in 2000!

Q AT PAGES 10-11 OF HIS TESTIMONY, RMP WITNESS THORNTON REFERENCES EARLIER REVIEWS OF THESE DIFFERENCES AND SAYS THAT A WORKING GROUP ESTABLISHED IN DOCKET NO. 01-035-01 CONCLUDED IT WAS NOT NECESSARY TO TRY TO ADJUST FOR THESE DIFFERENCES. IF THAT WAS APPROPRIATE THEN, IS IT STILL?

A No. Notably, the docket referenced for that evaluation is the source of the load data shown on Exhibit UIEC ____ (MEB-2). As noted, the differences were small then; they are not small anymore, as the data clearly shows.

Q TO THE EXTENT THAT THERE ARE DIFFERENCES IN THE CONTRIBUTIONS TO JURISDICTIONAL PEAK LOADS AND THE LEVEL OF JURISDICTIONAL PEAK LOADS THEMSELVES BETWEEN THE CLASS STUDY AND THE JURISDICTIONAL STUDY, TO WHAT CUSTOMER CLASSES WOULD YOU ATTRIBUTE THE DIFFERENCE?

A The difference would mainly be attributed to those customer classes for which the Company must rely upon load research data.

Q WHICH ARE THOSE CLASSES?

A Those are Residential Schedule 1, Large General Service Schedule 6, and Small General Service Schedule 23. Recall that these are the classes where the load research samples are of the early 1990s vintage, and that class usage characteristics and system load shape have changed materially since these samples were selected and installed. The differences are less likely to be attributable to those customer classes where RMP has demand metering and can measure the actual hourly loads of classes. These are, of course, Schedules 8 and 9 and contract customers.

Q TO THE EXTENT THAT THE DEMANDS AT THE TIME OF THE SYSTEM PEAK OF SCHEDULES 1, 6 AND 23 ARE UNDERSTATED, WHAT IS THE IMPACT ON THE CLASS COST OF SERVICE STUDY?

A The impact would be to allocate too small of a percentage of costs to these classes, and too large of a percentage of the costs to the demand metered customer classes whose loads are accurately stated in the cost of service study.

<u>If a COS Study is to be Used, at a Minimum, the Loads Must be Adjusted</u>

Q HAVE YOU DEVELOPED A CLASS COST OF SERVICE STUDY USING CLASS CONTRIBUTIONS TO THE SYSTEM PEAK LOADS THAT EQUAL THE CONTRIBUTIONS OF THE UTAH JURISDICTION TO THE SYSTEM PEAK LOADS THAT WERE USED IN THE JURISDICTIONAL ALLOCATION FOR REVENUE REQUIREMENT PURPOSES?

A Yes. This is presented in Exhibit UIEC ____ (MEB-3).

Q HOW WAS THIS COST OF SERVICE STUDY DEVELOPED?

A The only change from the class cost of service study filed by RMP was to adjust the loads of Schedules 1, 6 and 23, by month, so that in each month the sum of the class contributions to the system peak in the class study equals the jurisdictional contribution to the system peak in the revenue requirement study used in this proceeding.

Page 1 of Exhibit UIEC ____ (MEB-3) shows the overall summary of the class cost of service results at present rates. This is the same format as the summaries presented by RMP. Column M shows the increases or decreases at the rate of return at present rates required to move each customer class to the jurisdictional average rate of return.

Page 2 shows the cost of service results and the percentage changes from current revenue to move each class to the claimed 8.37% return on rate base.

Q WHAT IS THE IMPACT OF THIS ADJUSTMENT?

A I conclude that with the adjustments made to loads in order to conform the class loads to the jurisdictional loads used to allocate costs to Utah, the indicated increases for most of the major customer classes are closer together than was the case under RMP's cost of service study. The indicated departures from cost of service are smaller for Residential Schedule 1, Large General Service Schedule 6 and Schedule 9. They are about the same for the other classes.

Q DID YOU ADJUST ANY OF THE LOADS OTHER THAN THE CONTRIBUTIONS TO THE SYSTEM PEAK DEMANDS?

A No. I only adjusted the contributions to the system peak demands. To the extent that those demands were understated, it is to be expected that the class peak demands and the individual customer peak demands also are understated. I have not corrected these understatements in the cost study, and thus the results shown, even with the corrections for contributions to system peak, still overstate the rate of return on these customer classes, and understate the degree of adjustment required to move them to cost of service.

The 12CP-75/25 Methodology Should be Changed

Q ARE THERE OTHER MAJOR ISSUES IMPACTING THE VALIDITY OF THE COST OF SERVICE STUDY THAT SHOULD BE CONSIDERED?

A Yes. It has been many years since the Commission adopted the current 75% demand/25% energy weighting and the use of 12 monthly coincident peaks to allocate generation costs among customer classes. (While there have been some minor variations since that time, the basic approach still remains in effect.) In light of the significant increases (both historic and forecasted) in summer peak loads as compared to loads in other seasons, and the increases in wholesale electricity market prices during summer months, it clearly is time to revisit the appropriateness of the entire 12CP-75/25 cost allocation.

Q WHEN WAS THE 12CP-75/25 COST ALLOCATION FIRST ADOPTED?

A It was adopted following the merger between Utah Power and Light Company and Pacific Power and Light Company. Utah Power and Light Company had been using an eight coincident peak cost allocation method, and Pacific Power and Light Company had been using a method of allocation that included an energy component.

Q HAVE YOU PREPARED ANY MATERIAL TO SHOW THE LOAD SHAPES AND THE CHANGES OVER TIME?

A Yes. Page 1 of Exhibit UIEC ____ (MEB-4) shows, for several time periods, the monthly loads on the Utah jurisdictional system at the times of the system monthly peak loads. Utah clearly has a dominant summer peak demand. Exhibit UIEC ____ (MEB-4), page 2, shows the monthly system peaks, as a percentage of the annual peak, for four different time periods for the PacifiCorp system. These are 1990 (when the system was winter peaking), 2007 and 2008 (the two most recently completed calendar years) and the forecasted test year in this proceeding.

A review of this information clearly shows that the summer period demands on the system are now dominant. It is the summer peak load, and the growth in it, that is the driver for adding capacity to the system.

The 1990 load data shown on page 2 of Exhibit UIEC ____ (MEB-4), is representative of the load shape at the time that PacifiCorp originally presented the 12CP-75/25 allocation method. A review of the various years on this graph clearly shows that the system has changed substantially. The 12CP-75/25 method was later applied to the allocation of Utah jurisdictional costs to customer classes. In addition to the overall change in system load shape and the increasing dominance of the summer peak loads, the inter-jurisdictional allocation philosophy also has changed. For example, the Revised Protocol now being used for inter-jurisdictional allocations reduces further the benefits of hydroelectric capacity for Utah customers. (Part of the original justification used by Pacific Power and Light Company for its energy-based allocation was the presence of hydroelectric capacity on the Northwest System.) As that benefit continues to diminish, any justification for the 25% energy classification diminishes with it.

Q HAS RMP ATTEMPTED TO JUSTIFY THE USE OF THE 12CP-75/25 METHOD IN THIS CASE?

A No. It essentially relies on past precedent and the inter-jurisdictional allocation study. The load shape changes show that the precedent is outdated.

Reliance upon an inter-jurisdictional allocation method also is not appropriate. As every participant to this proceeding is aware, the jurisdictional allocation method has evolved over time and is the product of trying to accommodate concerns of a wide variety of parties. There is not necessarily any "cost causation" basis to this study. Rather, inter-jurisdictional allocations have become more of an effort to provide the utility with an enhanced opportunity to collect 100% of its costs across all jurisdictions, while still accommodating particular jurisdictional priorities and preferences.

In addition, load shape differences between classes within a state are far greater than differences in load shape between jurisdictions. What is an acceptable compromise at the jurisdictional level because of a small impact creates large inequities when applied to classes with widely varying load patterns. Thus, reliance upon an inter-jurisdictional allocation method as a basis for the class cost of service study is inappropriate.

Q TO WHAT COSTS DOES RMP APPLY THE 12CP-75/25 METHODOLOGY?

A RMP applies it to all of its generation and transmission fixed costs.

Q IS IT APPROPRIATE TO APPLY THIS HYBRID ALLOCATION FACTOR TO ALL OF THESE FIXED COSTS?

A No, it is not. If RMP wants to consider energy as either part of the classification of these costs, or include it in a composite allocation factor, it should analyze each investment within the generation and transmission functions with a view toward determining analytically whether or not some energy component would be justified. Merely to apply the same 25% factor across all assets (especially when there is no justification presented at all for 25%) is not consistent with appropriate cost of service principles.

Q IN ITS 12CP FACTOR, DOES RMP WEIGHT EACH MONTH IN PROPORTION TO THE SIZE OF THE MONTHLY PEAK AS COMPARED TO THE ANNUAL PEAK?

A It does. However, the result is not significantly different from an un-weighted factor.

RMP's 12CP-75/25 Method is Equivalent to Allocating 25% of Generation and Transmission Fixed Costs on Energy

Q IS THE 75/25 METHOD EMPLOYED BY RMP IN THE ALLOCATION EQUIVALENT TO CLASSIFYING 25% OF THE INVESTMENT IN GENERATION AND TRANSMISSION, AND RELATED COSTS, AS ENERGY-RELATED?

A Yes. The difference is only in the mechanics of the calculation. RMP's approach to cost of service for generation and transmission fixed costs – which is to weight the demand allocation factor 75% and the energy allocation factor 25% in order to derive a composite allocator – is mathematically equivalent to classifying 25% of these costs as energy-related and allocating them to classes using the energy allocation factor, and classifying 75% of them as demand and allocating to customer classes using the demand allocation factor.

Q HAVE YOU PREPARED A SCHEDULE WHICH SUMMARIZES HOW RMP TREATS GENERATION AND TRANSMISSION INVESTMENT AND RELATED FIXED COSTS?

A Yes. Exhibit UIEC ____ (MEB-5) presents a schedule which summarizes how RMP treats these costs. In order to show more clearly the nature of RMP's treatment, I have noted their approach as classifying 25% of these costs as energy-related, and 75% as demand-related.

Q DOES THIS EXHIBIT ALSO SHOW HOW YOU WOULD RECOMMEND THAT THESE COSTS BE TREATED?

A Yes. I recommend that 100% of the costs be classified as demand-related, and allocated using a demand allocation factor. In particular, costs should be allocated using summer loads. As Exhibit UIEC ____ (MEB-4) showed, system and jurisdictional loads are highest in the summer.

In addition, the widely divergent nature of class load patterns further supports use of loads from the peak summer period.

I will expand on the reason for my recommendation in more detail in the next several sections.

Class Load Patterns Vary Widely

Q HAVE YOU PREPARED ANY MATERIAL TO ILLUSTRATE THE PATTERN OF THE LOADS OF MAJOR CLASSES ON THE RMP SYSTEM?

A Yes. Exhibit UIEC ____ (MEB-6) presents three graphs. The graph on page 1 shows the demands of each of the major classes at the times of the monthly system peaks, the graph on page 2 shows the demands on an hourly basis on the system peak day, and the graph on page 3 shows the load pattern over a weekly cycle.

Q PLEASE EXPLAIN THESE GRAPHS.

A Page 1 shows the contributions of classes to each of the monthly peak demands and the overall general system load shape in Utah. Obviously, the residential class summer demands are driving the system load shape. They nearly double from their spring and fall lows to the summer peak. Rate Schedule 6 customers experience higher demands in the summer than during other months, but the difference or disparity is not nearly as large as is the case for the residential customers.

Q WHAT IS SHOWN ON PAGE 2?

A Page 2 shows how the loads of these same classes vary over the 24 hours of a day. For illustration, the loads on the system peak day for 2008 have been used. Once again, it is easy to see that it is mainly the residential, and to a lesser extent Schedule 6, customers who drive the daily system load shape. It is these loads for which RMP contracts for seasonal power purchases, and/or runs peaking units. The peaking units have an annual ownership cost as a result of being on RMP's books, and much of the purchased power is for at least 16 hours a day, five days a week, even though the power may not be needed for all of these hours, and may not be needed at all on other days.

Page 3 shows the hourly loads during the peak summer week for 2008. The graph begins at midnight on July 6 and continues through midnight on July 12. Note that over this entire week, there is only a small variation in the loads of Schedule 9 customers.

The line at the top of the graph shows the variations in the loads of the entire Utah jurisdiction. Since Schedule 9 customer loads are relatively constant, it is obvious that the other customer classes are causing this load shape. Essentially, from midnight to the afternoon peak, the load swings from approximately 2,300 megawatts to 4,300 megawatts, a swing of 2,000 megawatts, or more than 80% from the daily low to the high.

These kinds of loads are very expensive to serve because the cost of being able to have the capacity necessary to serve the peak is not extensively utilized in non-peak times. This makes the unit costs very high.

Q DOES RMP'S 12CP-75/25 ALLOCATION METHOD CAPTURE THE COSTS ASSOCIATED WITH THESE KINDS OF LOAD PATTERNS?

A No. The 12CP-75/25 allocation method employed by RMP does not at all capture the costs associated with these kinds of load patterns. Rather, it effectively socializes the costs associated with the owned and purchased capacity needed to serve these load excursions, and allocates them to everyone.

Q DOESN'T RMP ALLOCATE SOME OF THE SEASONAL PURCHASED POWER CONTRACTS USING JUST SUMMER PEAK LOADS?

A It does. But instead of using the difference between loads in the summer and loads in other months, which is what causes the need for the extra purchased power in the summer, RMP allocates those costs to all summer load, including the summer load of those customers who do not have a peaking load shape. As a result, this allocation does not effectively address the issue.

Q ARE FUEL COSTS ALLOCATED MONTHLY?

A Yes, but the end result for most classes is not significantly different from an annual allocation.

Why Fixed Costs Should be Allocated on Demand, and Energy Costs on Energy

Q DOES THE FACT THAT UTILITIES CAN SELECT FROM DIFFERENT KINDS OF GENERATION FACILITIES, SUCH AS BASE LOAD, INTERMEDIATE AND PEAKING, PROVIDE A JUSTIFICATION FOR CLASSIFYING PART OF THE INVESTMENT IN GENERATION FACILITIES AS ENERGY-RELATED?

A No. It is true that utilities select the mix of generation facilities that they expect to be able to produce power at the lowest overall total cost, which takes into account the combination of fixed costs and variable costs. But, once that decision is made, the amount of fixed costs on the system is set and does not vary with kilowatt-hour output or the number of hours that the facility is operated. These are truly fixed costs, which traditional allocation methods treat as demand-related costs and allocate to customer classes based on a method such as coincident peak or "Average and Excess Demand" (AED). The types of fuel used are defined by the specific technology employed, but the total fuel cost varies as a function of the total kilowatt-hour output – and thus is treated as a variable cost and allocated to classes on the basis of energy consumption.

Q IS THIS TECHNOLOGY DISTINCTION IMPORTANT FOR PURPOSES OF PERFORMING CLASS COST ALLOCATION STUDIES?

A No, under traditional allocation approaches, it is not. While it is recognized that the different technologies have different combinations of fixed costs and variable costs, any distinction that would attempt to more precisely articulate costs by customer class would require an extensive analysis to determine the technology or technologies that would be installed if a utility served each customer class independently, at its own lowest cost.

The result would be that for high load factor customer classes relatively more base load plant would be installed, and relatively less peaking plant would be installed. The converse would be true for lower load factor customers – that is, relatively more peaking plant would be installed and relatively less base load plant would be installed. If this were done, then the high load factor class would be allocated more fixed costs, but also the lower variable costs associated with the base load plants; and the low load factor customer class would be allocated less capital costs, but also the higher variable costs associated with the peaking units.

This type of analysis properly would reflect the trade-off between capital costs and fuel costs associated with this more precise distinction. If this specific analysis were done for each class on a stand-alone basis, then the results of this analysis would have to be analyzed to determine how to apply them to the <u>actual</u> fixed costs and variable costs which the utility has incurred in pursuit of its goal of selecting that combination of technologies which serves its <u>total</u> load at the lowest <u>total</u> fixed plus variable cost.

If there is a desire to reflect these technology tradeoffs more specifically, then this type of detailed analysis would be required. RMP has provided absolutely no analysis that even comes close to considering these factors. Rather, it has arbitrarily chosen a methodology which is the equivalent of classifying 25% of all fixed generation (as well as transmission) costs as energy-related, and allocating those costs to customer classes on the basis of energy. This approach is overly simplistic and incomplete.

Q HOW DO TRADITIONAL COST ALLOCATION STUDIES RECOGNIZE THIS MIX OF TECHNOLOGIES?

A Traditional cost allocation studies recognize that the mix or combination of plants is built to serve the overall or combined load characteristics of all customer classes – and not for the load characteristics of any particular customer class. These methods, therefore, allocate energy costs across all customer classes on an equal cents per kWh basis, and allocate fixed costs equally across all customer classes on a uniform dollars per kW of demand basis. This approach is reasonable, and avoids a lot of complexity and assumptions that would be required if one were to attempt to more precisely identify the specific mix of plants and the resulting separately determined capital and fuel costs.

Q IS THE METHODOLOGY EMPLOYED BY RMP GENERALLY ACCEPTED AND USED IN THE ELECTRIC UTILITY INDUSTRY?

A No, it is not. The most frequently used allocation methods in the electric industry today are those which focus on demands occurring during the high load hours on a utility's system. For example, a coincident peak allocation based on loads occurring during the high load months, or an AED allocation method which utilizes both class average demands and the excess of class peak demands over average demand in the allocation methodology. The 12CP-75/25 method employed by RMP does not fit within the scope of either of these two families of allocation methods.

As mentioned earlier, if RMP wants to include some energy component in the allocation of these costs, then it needs to perform some analysis of the nature, purpose and characteristics of each of the assets in order to analytically develop a number that has some basis.

Results of 12CP Allocation

Q WHAT IMPACT WOULD AN ALLOCATION OF GENERATION AND TRANSMISSION INVESTMENT BASED ON DEMANDS ONLY, WITHOUT AN ENERGY WEIGHTING OR COMPONENT, HAVE ON THE RESULTS OF THE CLASS COST OF SERVICE STUDY?

A This is shown on pages 1 and 2 of Exhibit UIEC ____ (MEB-7). This study uses the class contributions to system peaks from UIEC ____ (MEB-3), and sets the demand percentage to 100%. As shown on page 1, the Schedule 9 rate of return is about equal to the system average rate of return, and as shown on page 2, the increase required to equal the proposed rate of return is within one percentage point of the average increase.

Results of 3CP and AED Allocations

Q HAVE YOU PREPARED ANY OTHER COST OF SERVICE STUDIES?

A Yes. Exhibit UIEC ____ (MEB-8) uses the class contributions to system peaks from UIEC ____ (MEB-3), sets the demand percentage to 100%, and substitutes the class demands at the time of the three highest summer monthly peak demands for the generation and transmission capacity cost allocation factor.

Exhibit UIEC ____ (MEB-9) uses the AED method. In this allocation, the peak of each class occurring during the summer months was used to determine the "excess" demands.

Q WHAT ARE THE RESULTS OF THESE STUDIES?

A With the 3CP allocation methodology, Schedule 9 customers are shown to be earning a rate of return substantially in excess of the system average, and deserving of a rate reduction on a revenue neutral basis, and in fact a rate reduction of nearly 4% based on RMP's proposed overall increase of 4.6%.

The result for Schedule 9 is about the same under the AED method.

Recommendation on Revenue Allocation

Q PUTTING ASIDE THE ISSUES OF CLASS AND CUSTOMER PEAKS, DO THE ADJUSTMENTS YOU HAVE MADE TO CLASS LOADS MAKE THE RESULTS A RELIABLE INDICATOR OF CLASS COST OF SERVICE?

A I believe that they are more accurate than RMP's class cost of service study, but still fall short of the quality and accuracy of results that would be appropriate to support reliance upon these results in the allocation of any change in revenue requirements to customer classes.

Q ARE THERE ANY ISSUES WITH RESPECT TO THE COMPOSITION OF CUSTOMER CLASSES, PARTICULARLY SCHEDULE 9, THAT CAUSE CONCERNS ABOUT THE ACCURACY OF THE RESULTS?

A Yes. Schedule 9 customers are mostly Industrial customers, but the class as constituted by RMP does contain some Commercial and Public Authority customers. RMP has not provided sufficient information to allow a determination to be made of whether the load characteristics of these three groups of customers are similar enough to be included in the same rate schedule. To the extent that there are material differences in load characteristics, inclusion of all three groups of customers in the same rate schedule and cost of service class could introduce distortions into the resulting measurement of class rate of return.

In addition, this class in the cost of service study consists of Schedule 9 customers and Schedule 9A customers. The cost of service measurement does not provide an articulation that will allow separation of the costs between these two schedules, and thus does not provide information sufficient for accurate rate design.

Q IN LIGHT OF THESE RESULTS AND THE AGE OF THE LOAD RESEARCH SAMPLE DATA, DO YOU HAVE A RECOMMENDATION AS TO HOW ANY CHANGE IN REVENUES THAT MAY RESULT FROM THIS CASE SHOULD BE SPREAD TO THE VARIOUS CUSTOMER CLASSES?

A Yes. It is my recommendation that any change in revenues approved for RMP in this proceeding be allocated to the various rate schedules and customer classes as an equal percent applied to current revenues. This will maintain the existing inter-class rate relationships until such time as more accurate class cost of service load data and cost of service studies are available.

Q IF THE COMMISSION WERE TO DECIDE TO UTILIZE CLASS COST OF SERVICE AS A GUIDE IN THIS CASE, WHAT ADJUSTMENTS TO RMP'S COST OF SERVICE STUDY SHOULD BE MADE?

A In addition to adjusting the class load data, it would be my recommendation to use classification and allocation methods that do not classify or allocate any portion of the generation and transmission fixed costs on energy. It also would be appropriate to base the allocation of fixed costs on demands occurring during the summer months, by using either the 3CP allocation method or an AED method, as discussed above.

ENERGY COST ADJUSTMENT

Q ARE YOU AWARE THAT IN A SEPARATE PROCEEDING, DOCKET NO. 09-035-15, THE COMMISSION WILL BE CONSIDERING THE ADOPTION OF AN ENERGY COST ADJUSTMENT MECHANISM (ECAM) FOR RMP?

A Yes.

Q WHAT IS THE RELATIONSHIP BETWEEN THE ECAM DOCKET AND THIS DOCKET?

A There should not be any relationship.

Q PLEASE EXPLAIN.

A If the Commission decides to permit RMP to have some form of ECAM, it must make a determination as to which elements of energy costs should be tracked, and how to collect the costs associated with that tracking from the various customer classes and rate schedules of RMP. Until such time as a determination is made as to the specific kinds of costs to be tracked through the ECAM, it is not possible to know how to segregate the components of the fuel and variable purchased power costs in the cost of service study.

Q WHAT ARE THE IMPLICATIONS OF THESE FACTS FOR HOW TO ALLOCATE ANY CHANGE IN REVENUE REQUIREMENTS IN THIS CASE?

A The implication clearly is that any adjustment that is made to revenue requirements in this case should be applied as an equal percentage across-the-board change. Any more specific articulation of costs by customer class, time of use, or any other differentiating characteristic must await a determination in the ECAM case as to both the need for an ECAM, and the form of the ECAM, if, in fact, some type of ECAM is adopted.

Having made those decisions, then if there is to be an ECAM, it can be implemented in the next GRC with the benefit of knowing the parameters of the ECAM.

TRANSMISSION REVENUE REQUIREMENT

Q HAVE YOU REVIEWED RMP'S REPRESENTATIONS WITH RESPECT TO THE REVENUE REQUIREMENT ASSOCIATED WITH TRANSMISSION?

A Yes. As expressed in RMP's testimony, and in particular page 2 of Exhibit CCP-1, the proposed pro forma transmission-related revenue requirement is $118 million for the Utah jurisdiction.

Q ARE YOU FAMILIAR WITH THE FILING AT THE FEDERAL ENERGY REGULATORY COMMISSION (FERC) BY PACIFICORP OF ITS OPEN ACCESS TRANSMISSION TARIFF (OATT) UPDATE AS OF AUGUST 31, 2009?

A Yes. In that update, PacifiCorp delineates its transmission revenue requirement and the allocation of that revenue requirement to its various retail jurisdictions, including Utah retail, and to other transmission loads.

Q WHAT AMOUNT OF REVENUE REQUIREMENT IS ATTRIBUTED TO THE UTAH RETAIL JURISDICTIONAL LOAD IN THAT FILING?

A In that filing at FERC, RMP attributes to the retail jurisdiction in Utah a revenue requirement of $55 million. This is substantially lower than the $118 million revenue requirement which RMP asks this Commission to include in retail rates in this case for transmission service.

Q ARE YOU ABLE TO EXPLAIN THE DIFFERENCE IN THESE NUMBERS?

A No. While I would not expect them to be exactly equal, I also would not expect the magnitude of disparity that is apparent in these two different determinations of the transmission service revenue requirement associated with retail service supplied to Utah jurisdictional customers. While there may be rational explanations for the difference, they are not currently apparent.

Q WHAT IS YOUR RECOMMENDATION?

A It is my recommendation that RMP provide whatever reconciliation and explanation it is able to provide in its rebuttal testimony in this proceeding. If the explanation provided by RMP is inadequate or unpersuasive, then I would recommend that the Commission adopt the revenue requirement for transmission service that RMP has claimed in its OATT update filing with the FERC.

HEDGING PRACTICES

Q HAVE YOU REVIEWED RMP'S PRACTICES WITH RESPECT TO THE ACQUISITION OF NATURAL GAS?

A Yes. RMP has followed a practice of entering into forward commitments for the purchase of its forecasted natural gas requirements. Its practice is to ramp up its price commitments over a period of several years, with the level of the commitment escalating over time. For example, according to the 10-K report, issued in February 2009, as of December 31, 2008, RMP had hedged 94% of its forecasted financial exposure for the year 2009. For 2010, PacifiCorp had hedged 48% of its forecasted physical exposure and 85% of its forecasted financial exposure. RMP does this either by contracting for a fixed price with a supplier, or through the use of indexes and swaps. Under the index and swap approach, RMP agrees to pay some specified market index price to a supplier for the gas. At that time, or a later time, it enters into a transaction with a third party (counter party) to swap the index price for a fixed price that is established at the time the financial transaction with the third party takes place. The end result is the same, namely that the price to be paid for the commodity when it is delivered at a future time is established in advance.

Q UNDER RMP'S STRATEGY, WHAT IS THE PRICE PAID AT THE TIME OF DELIVERY IF THE MARKET PRICE (INDEX) IS HIGHER THAN THE SWAP PRICE?

A Regardless of whether the market price is higher or lower than the swap price, RMP effectively pays the swap price. In terms of the transaction structure, RMP pays the index price to the supplier of physical natural gas. If its index price is lower than the swap price, RMP would pay the difference to the counter party on the swap transaction. If the index price is higher than the swap price, the counter party pays the difference to RMP.

The swap transaction with its fixed price protects from upswings in market prices, but does not provide RMP with the opportunity to benefit if market prices turn out to be lower than the swap price.

Q DID THAT HAPPEN IN THE TEST YEAR IN THIS CASE?

A Yes. Based on Mr. Duvall's exhibit, it appears that the swap prices produce a cost that exceeds the market prices included in his exhibit by $174 million.

Q ARE THERE WAYS TO PROTECT AGAINST PRICE FLY-UPS, BUT STILL MAINTAIN THE FLEXIBILITY TO BENEFIT IF MARKET PRICES DECLINE?

A Yes. A call option arrangement provides that protection against upward price movement while retaining the opportunity to benefit if the prices decline.

Q WHAT IS A CALL OPTION?

A A call option contract gives the buyer (RMP in this case) the right, but not the obligation, to acquire a specified volume of natural gas (or other product) at a designated location, at a specified time and at a specified price. The buyer pays the seller an option price, or premium, for this right.

To illustrate, assume that RMP entered into a call option contract for a future month that gave it the right (but not the obligation) to receive 10,000 MMBtu per day at a price of $5.00 per MMBtu. Suppose, then, in the future month when the option was exercisable, the actual market price was $6.00 per MMBtu. Since the strike price in the option contract ($5.00) is lower than the market price, RMP would exercise the option and acquire the gas at $5.00 per MMBtu, benefitting to the extent of $1.00 per MMBtu on the commodity received, relative to the market. This is the same price ($5.00) that RMP would have paid had it entered into a swap for $5.00.

Suppose, on the other hand, that the market price had dropped to $4.00 per MMBtu for that month. In that event, RMP would purchase at the market price of

$4.00 per MMBtu and let the option expire, thereby benefitting to the extent of $1.00 per MMBtu as a result of the decline in the market.

Thus, under an option strategy, in return for paying the option premium, the buyer is protected against escalations in the market price above the call option strike price, but retains the ability to benefit from declines in market price relative to the strike price.

Q DO OTHER ELECTRIC UTILITIES WITH SIGNIFICANT MARKET EXPOSURE TO NATURAL GAS AND ELECTRICITY PRICES UTILIZE OPTIONS?

A Yes, they do. One of the more concise descriptions of a hedging program for natural gas and power purchases was provided by Aquila Inc. witness Gary Gottsch in a recent rate proceeding in the state of Missouri. In his testimony Mr. Gottsch stated:

> Q. Can you summarize Aquila's natural gas hedging program for electric generation and on-peak purchased power?
>
> A. Aquila's approach for hedging natural gas and on-peak purchased power is to procure one-third of the monthly forecast quantity through fixed price NYMEX swaps, one-third in option contracts (straight calls or collars), and the remaining one-third at the then prevailing daily or monthly market indexes. These positions are acquired over a 28 month process that allows the Company to capture a greater averaging effect.
>
> Q. Why does Aquila believe that this hedging approach is appropriate?
>
> A. This approach allows Aquila to mitigate the natural gas price volatility (via fixed price and option contracts) while still allowing it to take advantage of decreases in natural gas prices (via option contracts and index purchases). (Missouri Public Service Commission, Docket No. ER-2007-0004, Direct Testimony of Gary L. Gottsch at page 2, lines 11-21, July 3, 2006).

Another electric utility that uses options to reduce market exposure to natural gas prices is Sierra Pacific Power Company, d/b/a Nevada Energy (NVEnergy). In 2006, the Public Utilities Commission of Nevada (PUCN) approved a stipulation whereby NVEnergy and the parties agreed that the gas hedging strategy would be:

(i) to leave open 25% of the Company's projected financial gas exposure for each season; (ii) to hedge 50% of the Company's projected financial gas exposure with fixed price products for each season; and (iii) to hedge 25% of the Company's projected financial gas exposure for each season with collars. (PUCN, Docket No. 06-07010, Order, Stipulation ¶ 1, Oct. 5, 2006). In 2008, NVEnergy proposed to expand its natural gas hedging strategy to hedge 100% of its projected financial gas exposure for the three months of July, August, and September. It proposed to hedge 67% of projected financial gas exposure with fixed price products and 33% of projected financial gas exposure with collars. Its current hedging strategy would remain in place for all other months. (PUCN, Docket No. 08-0831, Order ¶ 191, Dec. 17, 2008).

The PUCN denied NVEnergy's request. The PUCN stated that NVEnergy's "…existing hedging strategy balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of the plan." (Id. ¶ 197).

Q DID YOU REVIEW THE DISCOVERY IN THIS CASE, IN THE HEDGING CASE (DOCKET NO. 09-035-21) AND THE ECAM CASE (DOCKET NO. 09-035-15) WITH RESPECT TO THE ISSUE OF HEDGING?

A Yes. I have reviewed the responses of all data requests that address this issue, including the "secret" documents that were available for review only in Salt Lake City at RMP's offices.

Q **IN THAT DISCOVERY DID YOU SEE ANY EVIDENCE THAT RMP HAD CONSIDERED THE USE OF CALL OPTION CONTRACTS AS PART OF ITS RESOURCE ACQUISITION STRATEGY?**

A I did not. The documents I saw clearly permit the use of call option contracts, but in the material supplied there was no discussion about the use of call option contracts, nor does it appear that any were entered into.

Q **WHAT IS YOUR RECOMMENDATION?**

A This is an issue that clearly needs to be explored in more detail. RMP needs to explain why it has not used call options for at least a portion of its anticipated requirements. If it has considered the use of call options and made a decision not to, it needs to explain the analysis process and the conclusion. If it has not considered call option contracts, it needs to explain why not. The Commission may also want to include this issue in the ECAM case, or in the hedging case, in order to ensure that the acquisition plans are in the best interests of the customers.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes.

Qualifications of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission (FERC), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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CERTIFICATE OF SERVICE
(Docket No. 09-035-23)

I hereby certify that on this 8th day of October 2009, I caused to be e-mailed, a true and correct copy of the foregoing DIRECT TESTIMONY AND EXHIBITS OF MAURICE BRUBAKER to:

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