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

A. My name is Steven R. McDougal and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah, 84111.

Qualifications

Q. What is your current position at the Company and what is your employment history?

A. I am currently employed as the director of revenue requirements for the Company. I have been employed by Rocky Mountain Power or its predecessor companies since 1983. My experience at Rocky Mountain Power includes various positions within regulation, finance, resource planning, and internal audit.

Q. What are your responsibilities as director of revenue requirements?

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings or revenue requirement, assuring that the inter-jurisdictional cost allocation methodology is correctly applied, and the explanation of those calculations to regulators in the jurisdictions in which the Company operates.

Q. What is your educational background?

A. I received a Master of Accountancy from Brigham Young University with an emphasis in Management Advisory Services in 1983 and a Bachelor of Science degree in Accounting from Brigham Young University in 1982. In addition to my formal education, I have also attended various educational, professional and electric industry-related seminars.

Q. Have you testified in previous proceedings?

A. Yes. I have provided testimony before the Utah Public Service Commission, the Washington Utilities and Transportation Commission, the California Public Utilities Commission, the Idaho Public Utilities Commission, the Wyoming Public Service Commission and the Utah State Tax Commission.

Purpose of Testimony

Q. What is the purpose of your direct testimony?

A. My direct testimony addresses the calculation of the Company's Utah-allocated revenue requirement and the revenue increase requested in the Company's application. In support of this calculation, I provide testimony on the following:

- A summary of the calculation of the $1.592 billion dollar revenue requirement requested in this case. This represents a $160.6 million rate increase over Rocky Mountain Power's current rates, before considering any rate changes related to Docket No. 07-035-93.
- The need for the twelve months ending June 30, 2009 test period proposed in this case (the "Test Period").
- The Utah-allocated adjusted results of operations for the Test Period demonstrating that the Company will earn an overall return on equity ("ROE") in Utah of 6.1 percent.

Required Revenue Requirement

Q. What revenue requirement is needed to achieve the requested ROE in this case?

A. Exhibit RMP___(SRM-1) provides a summary of the Company's Utah-allocated results of operations for the Test Period, twelve months ending June 30, 2009. At current rate levels Rocky Mountain Power will earn an overall ROE in Utah of 6.1 percent during the Test Period. This return is less than the 10.25 percent ROE included in the stipulation in Docket No. 06-035-21 and is less than the 10.75 percent return requested by the Company in Docket No. 07-035-93 and recommended by Dr. Samuel C. Hadaway in this case. A revenue requirement of $1.623 billion would be required to produce the 10.75 percent ROE requested by the Company in this proceeding to provide a fair and equitable return for the Company's shareholders based on a Revised Protocol allocation methodology before the price cap, which reduces the revenue requirement to $1.592 billion. The Company used the Revised Protocol allocation method, as approved by the Commission in Docket No. 02-035-04 to calculate Utah's results of operations and the associated ROE.

Q. Please explain the Rate Mitigation Cap?

A. The Company has reflected the Rate Mitigation Cap as stipulated and approved by the Utah PSC in Docket No. 02-035-04. The stipulation states:

> "In order to mitigate potential rate impacts on Utah customers, any increase in the Utah revenue requirement as a result of the implementation of the Revised Protocol shall be capped at the Applicable Percentage of the Company's Utah Revenue Requirement calculated under the Rolled-In Allocation Method for the indicated effective periods as follows:
>
> a. 101.5 percent for the period from the effective date of the final PSCU order in the first general rate proceeding filed after the effective date of this Stipulation and the Revised Protocol, to March 31, 2007
>
> b. 101.25 percent for the period from April 1, 2007 to March 31, 2009."[1]

[1] Stipulation in Docket No. 02-035-04, page 3.

> "for the Company's fiscal years beginning April 1, 2009 through March 31, 2014, for all general rate proceedings, the Company's Utah revenue requirement to be used for purposes of setting rates for Utah customers will be the lesser of: (1) the Company's Utah revenue requirement calculated under the Rolled-In Allocation Method multiplied by 101.00 percent; or (ii) the Company's Utah revenue requirement resulting from the Revised Protocol"[2]

For purposes of this case, the Rate Mitigation Cap is computed by taking nine months of the 101.25 percent cap and three months of the 101.00 percent cap to align the mitigation cap with the Test Period. This weighted average results in a cap of 101.19 percent, and the adjustment reduces Utah's revenue requirement by $31.1 million. Consequently, the Company is requesting a revenue requirement of $1.592 billion as shown in my Exhibit RMP___(SRM-1) page 1.

Q. The Company filed this application prior to receiving a Commission order resolving issues raised in the previous general rate case Docket No. 07-035-93. How does this current case incorporate issues raised in that docket?

A. This case incorporates all adjustments or methodologies agreed to on an ongoing basis by the Company through the time of the hearings for Docket No. 07-035-93, including adjustments made to revenue requirement in the Company's rebuttal case and by any Company witness during the revenue requirement hearings that are applicable to the Test Period in this case. However, no change in the retail tariffs possibly resulting from that case has been assumed to be collected during the Test Period. To the extent the Commission grants the Company rate relief in Docket No. 07-035-93 additional retail revenue would need to be added to the Test Period in this case, effectively reducing the requested price increase.

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[2] Stipulation in Docket No. 02-035-04, page 4.

Q. Please explain why an additional price increase would be warranted in this case if the Company is granted rate relief in Docket No. 07-035-93.

A. Similar to the general rate case filed in Docket No. 07-035-93, the Company continues to incur cost increases to serve its customers in two main areas: new plant investment and net power costs. When compared to the costs included in the Company's last filed position in Docket No. 07-035-93, net electric plant in service allocated to Utah (gross plant offset by accumulated depreciation, amortization, and deferred income taxes) have increased over $700 million. This increase includes the effect of bringing new generating plants online by June 30, 2009, including over $1.35 billion invested for various new wind projects and the Chehalis combined cycle combustion turbine plant ("Chehalis"). Net power costs allocated to Utah have increased over $32 million as explained by Company witness Mr. Gregory N. Duvall.

Test Period

Q. What test period did the Company use to determine revenue requirement in this case?

A. The Company based its request on the results of operations for the period of time beginning July 1, 2008, and ending June 30, 2009.

Q. Why did the Company choose the year ending June 30, 2009, as the Test Period?

A. The Company's proposed Test Period is a conservative choice that balances the need for adequate cost recovery with the need for transparency and risk sharing between the Company and its customers. The primary objective of determining a test period is to develop normalized results of operations based on a period of time that will best reflect the conditions during which time the new rates will be in effect. Many factors must be considered to determine which test period best reflects those expected conditions. This Commission previously identified eight such factors[3], including:

(1) the general level of inflation;
(2) changes in the utility's investment, revenues, or expenses;
(3) changes in utility services;
(4) availability and accuracy of data to the parties;
(5) ability to synchronize the utility's investment, revenues, and expenses;
(6) whether the utility is in a cost increasing or cost declining status;
(7) incentives to efficient management and operation; and
(8) the length of time the new rates are expected to be in effect.

In its Order dated February 14, 2008, the Commission also expressed its desire to balance Company and ratepayer interests. The Company proposes the Test Period in this case after consideration of the current regulatory environment, state statutes governing test period development, and the business factors identified above by the Commission.

Q. Please describe how the Company considered the factors identified above in choosing the Test Period in this rate case.

A. Below is a brief discussion of the factors identified by the Commission and an explanation of how the Company evaluated its proposed Test Period based on these factors.

- **Level of Inflation –** The Company is facing inflationary pressure and needs to adjust amounts in the case to account for inflation. Inflation is expected to continue in the future as can be seen in the Global Insight non-labor inflation

[3] Commission Orders, Docket No. 04-035-42 and Docket No. 07-035-93

factors included on page 4.15 of Exhibit RMP___(SRM-2). The Company also has price increases included in many of its union labor contracts. In addition the Company is experiencing significant increases in net power costs as discussed by Mr. Duvall.

- **Changes in Utility Investment, Revenues, and Expenses –** As stated in Mr. A. Richard Walje's and Dr. Peter C. Eelkema's testimony, the Company expects a considerable amount of new load in the Utah service territory. Because of this load growth the Company will have to acquire new resources, impacting not only the level of investment needed to be included in rate base, but also retail revenues, net power costs and operation and maintenance costs.
- **Changes in Utility Services –** The Company has included anticipated changes in utility services, such as changes in Utah related to the installation and reading of automated meters (AMR).
- **Availability and Accuracy of Data to Parties –** The Company remains open and willing to share information with the parties involved in the case. The Company has provided answers to Master Data Request A concurrent with this filing. The Company is committed to responding to additional data requests from the parties in a timely manner.
- **Ability to Synchronize the Utility's Investment, Revenues, and Expenses –** It is important to synchronize the Company's investment, revenues and expenses with the level anticipated during the rate effective period. In order to synchronize all components of the revenue requirement with the rate effective period, it is essential that the Company be allowed to use forecast test periods

extending twenty months beyond the date of filing.

In this rate case, the Company is electing to use a test period less than twelve months beyond the date of filing to alleviate some of the concerns expressed in the test period hearings in Docket No. 07-035-93. The Company's costs are increasing mainly in the capital investment and net power cost area. To extent the forecast were to extend an additional 6 or 8 months, it would result in additional net power costs and retail revenues, and potentially higher jurisdictional cost allocations, which would have a tendency to be offsetting leaving increases in capital investment as the single largest increase in costs that the Company needs to address. For this reason, the Company has elected in this rate case to use a test period closer to the filing date and in-line with the Commission's most recent decision, but to include an adjustment to use end-of-period rate base to offset the cost pressures the Company is facing from adding new capital. Although this does not give the Company the full level of cost recovery we would be requesting in a forecast test period extending twenty months beyond the filing date that addressed perfect matching, and does not fully synchronize the investment, revenues and expenses with the anticipated rate effective period, it is an intermediary step the Company is proposing in this rate case.

- **Whether the Utility is in a Cost Increasing or Cost Declining Status –** As discussed in its direct testimony, the Company is in a time of increasing costs. The Company is experiencing significant increases in net power costs as well as increases in capital investments, which reflect the cost pressures facing the

Company. These increases are only partially offset by any increases in revenue associated with load growth.

- **Incentives to Efficient Management and Operation –** The Company management is continually looking for ways to increase the efficiency of the Company. The Company has reduced many costs related to employees and the overall number of employees; adjustments for these savings are included in the proposed Test Period. The Company is adding investment to serve load growth and improve reliability and needs the level of investment included in the proposed Test Period. To not allow the proposed test period would be a disincentive to the Company.
- **Length of Time New Rates Are Expected To Be in Effect –** The Company has not made any decision on the length of time the new rates are expected to be in effect. Future rate cases will be filed based on Utah jurisdictional earnings and the Company's ability to get timely recovery of its costs.

Q. Is a future test period necessary to represent the conditions expected when new rates are in effect?

A. Yes. In the current environment a future test period is the only adequate method to reflect the costs the Company will necessarily incur in the rate effective period to provide the level of service required by its customers. The Company expects a significant amount of new load in its Utah service territory and foresees continued load growth in other states that it serves. The need to serve growing load requires the Company to acquire new generating resources; the costs and benefits of some new generating resources are reflected in revenue requirement for the first time in this case. Significant new investments in transmission and distribution systems are required to integrate these new resources and ensure continued reliability. Net power costs continue to escalate as a result of increasing fuel costs, purchased power and load growth. Only a future test period can timely capture the rate-making impacts of growing customer load, the capital investment required to serve it and the operation and maintenance costs required to maintain system safety and reliability.

Q. What is the impact of "regulatory lag" on the Company?

A. "Regulatory lag" refers to the time difference between when costs are measured and approved for the Company's revenue requirement and when they are actually incurred in providing service to its customers. More than anything else, regulatory lag is the result of the rate-making process, including test period selection. If new rates do not reflect the costs being incurred at the time the rates are in effect, regulatory lag is created.

Regulatory lag is a serious problem for the Company when rates are based on a time period other than the anticipated rate effective period especially when the Company is experiencing a steady upward trend in investments and net power costs. Basing rates on a test period that doesn't reflect the true costs to serve customers during the rate effective period effectively denies the Company a reasonable opportunity to earn the return authorized by the Commission.

Q. When will a rate change likely become effective in this proceeding?

A. It is typical for orders in general rate cases to become effective near the end of the statutory 240-day period provided under section 54-7-12(3) of the Utah utility code. Based on the filing date of this case, the Company is requesting new rates to become effective in March, 2009.

Q. Is it important that the Test Period and the rate effective period be aligned?

A. Yes. As explained by Mr. Walje, the Company faces a rapidly changing business environment and significant inflation in the cost to serve our customers. During this period of rapid expansion and rate base growth, a historical test period cannot adequately capture the conditions that the Company will experience during the rate effective period; rather, it constrains the utility to chronically under-recover the true cost of service. The Company's proposed Test Period does not reach forward to the full extent allowed by statute to match with the rate effective period and extends to a period suggested by the Commission which we believe satisfies concerns regarding uncertainty that any party may have.

Q. Has the Company made any adjustments to address regulatory lag in this case?

A. Yes. As mentioned previously, the Company proposes to include end-of-period rate base, rather than using an average as it has done in previous cases. Because of the Test Period selected, only capital additions going into service by June 30, 2009, are included in the calculation of revenue requirement. This date is less than one year from the date of filing, reducing the exposure to movements in projections of capital spending. Adjusting to an end-of-period rate base, which is only twelve months beyond the date of filing and three months into the rate effective period, provides more certainty while reducing the lag associated with the Company's significant capital investment.

For purposes of this case, all rate base is first calculated using an average balance (thirteen month average for electric plant in service, beginning/ending average for other rate base accounts). Then in one adjustment, Adjustment 9.2 End-of-Period Rate Base, all rate base accounts are moved to the end of the test year (June 30, 2009).

Q. Did the Company consider any alternative test periods as it prepared this case?

A. Yes. The Company also prepared normalized results of operations based on a test period ending December 31, 2009, six months later than the end of the requested Test Period. Using a test period ending December 31, 2009 would have resulted in a $10.9 million higher rate increase request in this case, would have been within the twenty month time frame allowed for forecasted rate cases under Utah statute, and would have better aligned the test period with the rate effective period of this rate case.

Q. Is the test period in this case consistent with the test period ordered in Docket No. 07-035-93?

A. Yes. This case is consistent in that both cases use test periods extending approximately twelve months beyond the filing date. The Company prefers to use a test period extending twenty months beyond the filing date. However, in order to allow the Commission and other parties to become comfortable with using forecast test periods, we have decided that rather than going directly to using a twenty month forecast, we would abide by the Commission's most recent order and then make the transition in steps. Accordingly, the Company has also included as an adjustment in this case a movement to end-of-period rate base which appropriately increases revenue requirement to a level closer to that expected during the rate effective period while using information for a test period closer to the time of filing.

Q. Please explain how the Company developed the revenue requirement for the Test Period.

A. Revenue requirement preparation began with historical accounting information; in this case the Company used the twelve months ending December 31, 2007. Each of the revenue requirement components in that historical period was analyzed to determine if an adjustment is warranted to reflect normal operating conditions. The historical information was adjusted to recognize known, measurable and anticipated events and to include previously ordered Commission adjustments.

Q. What is the significance of Rocky Mountain Power's method of beginning with historical information?

A. The Company begins with historical accounting information and makes discrete adjustments to arrive at the Test Period revenue requirement. Beginning with historical information provides a realistic foundation that is readily available for audit by all who wish to participate in the case. Individual adjustments are also available for review, and regulators and intervenors may determine each adjustment's relevance and accuracy.

Q. Please summarize the process used to adjust the historical accounting information to reflect Test Period revenue and costs.

A. Historical retail revenue is first adjusted to reflect normal weather conditions and remove other items that should not be included in regulated results. Revenue is also adjusted for the effect of applying the current Commission-approved tariff rates to the Test Period load projection. The testimony of Dr. Eelkema describes the comprehensive approach used to project Test Period loads for this case. Net power costs were developed using the Generation & Regulation Initiative Decision ("GRID") model, which has been used extensively in prior general rate cases and other regulatory proceedings in Utah. The calculation of Test Period net power costs is described in the testimony of Company witness Mr. Duvall. Historical operations and maintenance ("O&M") expenses, excluding net power costs, were split into labor and non-labor components. Non-labor costs were adjusted for inflation using nationally-recognized inflation indices provided by Global Insight and for other discrete changes required to reflect conditions expected during the Test Period. Historical labor costs were also adjusted for expected increases through the end of the Test Period. Specific adjustments are described in greater detail later in my testimony and exhibits where I explain the development of the Utah results of operations.

Q. Does the Company rely solely on its own projections of future cost increases?

A. No. For example, the adjustment made to account for inflation between the historical period and the Test Period relies on inflation indices published by Global Insight which are developed specifically for electric utilities. In addition, the Company's projection of system load is informed by current and prospective customers as well as third-party economic studies and analyses.

Q. How has the Company addressed areas where cost increases were different than inflation?

A. The Company's business units were asked to provide regulation with any areas where budgets were significantly different than historic amounts, adjusted for wage increases and inflation. In addition, the revenue requirement developed in the case was compared to the Company's budget on a high level.

When differences were identified that needed to be adjusted in the rate case, the business units within the Company were asked to provide support for changes in the number, or frequency, of activities. Examples of these types of adjustments are the Utah AMR adjustment (Adjustment 8.10) which reflects efficiencies from the automated meter reading project, and the Incremental Generation O&M adjustment (Adjustment 4.13) which includes the cost of operating and maintaining new plants. These adjustments are necessary because inflation indices account for cost increases on existing units of production not changes in volume or processes.

Q. Is it possible to devise a test year that is free from some element of prediction?

A. Of course not. The reality is that the Commission is charged with setting rates for a future, not a historic, period and that inevitably involves a certain amount of informed projections of the future for any test period that is used. In prior years, historic test periods with no out-of-period adjustments have been used in an effort to remove Company judgment and discretion from the calculation of the revenue requirement. However, given the dynamic nature of the world in general and the electric industry in particular, it is unlikely that a pure historic test year will best reflect the conditions in the rate effective period at the present time; and, in fact, an unadjusted historic test year is not even an option that is available to the Commission under the current statute. All of the test year options require the Company to exercise informed judgment about how to best project future data or adjust historical data to reflect conditions in the rate effective period.

Q. Why is it important that the Company's process has been documented?

A. I believe that the care the Company has taken to document and explain its future test year along with its willingness to openly and voluntarily share information is the clearest indication that its approach is reasonable. I have explained that the Company has applied a rational, systematic and comprehensive approach to the preparation of its Test Period revenue requirement. Based on the factors I have previously described, I believe that the Test Period revenue requirement developed and proposed by the Company is fair and reasonable and is most likely to represent conditions in the rate effective period.

Q. Does using a future test year provide any benefit to customers?

A. When rates are matched with the true cost of providing service in the rate effective period, customers are presented an accurate price signal of the cost of electric service. This allows customers to make informed decisions about their energy consumption, usage patterns and conservation. To base utility rates in a high growth and rising cost period on outdated historical information will only result in the wrong price signal for customers and earnings erosion for the Company.

Q. If rate relief is granted based on projected costs, how can the Commission be assured that this additional funding will be used for the benefit of customers?

A. During this period of rapid system growth, the Company will have an ongoing need to continue a high level of investment in the system in order to maintain and increase service reliability. The Company is committed to filing Utah results of operations semi-annually with the Commission, DPU and CCS, a report that gives parties a chance to review the Company's earnings and verify that the Company is not earning more than its allowed rate of return.

Q. Do you have any other general observations about the use of a future test year?

A. The Commission is required by statute to choose the test year that best reflects the conditions in the rate effective period. The Utah Legislature has explicitly made a forecast test year option available to the Commission. The Company now finds itself in a period where costs are increasing significantly to meet customer demand for electricity. The Commission should require consumers to pay a price today that matches the cost to serve that customer today. Any business that charges prices today that reflect two-year-old costs will always under perform. A rate base, rate of return regulated utility like Rocky Mountain Power must be given a reasonable opportunity to earn its cost of capital. I believe that the Company's current circumstances are a perfect example of the need for a future test period that was anticipated by the Legislature.

Utah Results of Operations

Q. Please describe Exhibit RMP___(SRM-2).

A. Exhibit RMP___(SRM-2), which was prepared under my direction, is Rocky Mountain Power's Utah results of operations report (the "Report"). The starting point for the Report is the twelve months ended December 31, 2007, which has been normalized and is used to calculate the revenue requirement for the Test Period, the twelve months ended June 30, 2009. The Report provides totals for revenue, expenses, depreciation, net power costs, taxes, rate base and loads in the Test Period. Electric plant in service, accumulated depreciation and amortization reserve balances are initially calculated using a thirteen month average (matching generation investment with maintenance and net power costs), but ultimately all rate base is adjusted to be included based on the end-of-period balance. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit RMP___(SRM-2) is organized.

A. The Report is organized into sections marked with tabs. Tab 1 Summary contains the Utah-allocated results according to the Revised Protocol allocation methodology. Page 1.0 is the calculation of the Rate Mitigation Cap which compares the revenue requirement from Rolled-In to Revised Protocol and caps the increase at the lower of Revised Protocol or 101.19 percent of Rolled-In. Page 1.1, starting with the left-hand column 1 labeled Total Adjusted Results, is the Utah results of operations for the Test Period. The Total Adjusted Results column is carried forward from the results of operations summary, Page 2.2, and shows a

ROE for Utah of 6.1 percent. The capped revised protocol revenue requirement on line (3) shows the revenue requirement of $1.592 billion requested in this case. The Price Change (column 2 of Tab 1, page 1.1) shows that an increase of $191.6 million in revenues is required to increase the return on equity from 6.1 percent to 10.75 percent in Utah. Column 3 reflects the Utah adjusted revenue requirement of $1.623 billion with the $191.6 million price increase included. Page 1.2 of Tab 1 supports the calculation of additional revenue-related uncollectible expense and franchise taxes associated with the price change requested in column 2. Page 1.3 details the calculation of the net operating income percentage. Page 1.4 shows the same details as page 1.1 under the Rolled-In rather than the Revised Protocol allocation method. It is used in calculating the rate mitigation cap on page 1.0. Pages 1.5 through 1.6 contain a summary of adjustments made to the actual results to arrive at the Test Period.

Tab 2 details Total Company and Utah-allocated results based on the Revised Protocol allocation methodology. Pages 2.3 through 2.39 contain Total Company and Utah-allocated revenue, expenses and rate base detail by FERC account. Supporting documentation for the data in Tab 2, along with the normalizing adjustments required to reflect on-going costs of the Company, is provided under Tabs 3 through 9. The calculation of these adjustments is described later in my testimony. Tab 10 contains the calculation of the Revised Protocol allocation factors. Tab 11 is Tab 2 restated with the Utah allocation based on the Rolled-In allocation method.

Q. Is the Chehalis plant included in this rate case?

A. Yes. The net power costs, rate base, O&M and taxes associated with the Chehalis plant are included in this case. However, due to confidentiality, the Chehalis amounts are combined with other items. Confidential Exhibit RMP___(SRM-3) indicates the pages in Exhibit RMP___(SRM-2) that include Chehalis amounts, and gives a detailed breakout of these amounts.

Tab 3 – Revenue Adjustments

Q. Please describe the information contained behind Tab 3 Revenue Adjustments.

A. Tab 3 begins with the Revenue Adjustment Summary which is an overview of assumptions used to project retail revenue and a brief explanation of each additional normalization adjustment to other revenue. The numerical summary (pages 3.0.3 – 3.0.4) identifies each adjustment made to actual revenues and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments made to revenue in Tab 3.

A. **Temperature Normalization (page 3.1) –** This adjustment recalculates Utah revenue based on temperature normalized historical load. Revenue is adjusted to reflect an appropriate level assuming average temperature patterns. This adjustment also normalizes revenue for the Company's other jurisdictions for modeling purposes.

Revenue Normalization (page 3.2) – Several items are included in actual booked revenue that should not be included in regulatory results. These items include merger credits, Blue Sky program revenue, Cool Keeper program revenue, SMUD regulatory liability amortization, special contract pass-through revenue and out-of-period revenue. Additionally, situs contract revenue and non-metered lighting customer revenue are annualized in regulatory results. This adjustment correctly reflects each of these items for regulatory purposes. This adjustment also normalizes revenue in a similar manner for the Company's other jurisdictions for modeling purposes.

Effective Price Change (page 3.3) – This adjustment annualizes price changes occurring during calendar year 2007 as well as the effect of new rates for special contracts becoming effective during calendar year 2008. This adjustment also normalizes revenue for price changes in the Company's other jurisdictions for modeling purposes. This adjustment does not include the impact of any rate changes associated with docket 07-035-93 as these amounts are not known at this time.

Joint Use Revenues (page 3.4) – During 2007 several entries related to joint use revenue were booked to the incorrect FERC accounts and/or locations. This adjustment corrects the accounting entries to reflect proper account assignment and allocation factors.

Wheeling Revenues (page 3.5) – During 2007 there were various transactions regarding wheeling revenue that the Company does not expect to occur in the twelve months ended June 2009. These transactions relate to various prior period adjustments and contract terminations. This adjustment normalizes wheeling revenues to the anticipated level in the Test Period. This adjustment also includes pro forma wheeling revenue for the twelve months ended June 2009, including an adjustment to receive additional revenue for the Malin-Indian Springs contract.

Green Tag Revenues (page 3.6) – In order to help meet jurisdiction specific renewable portfolio standards, a market for green tags or Renewable Energy Credits ("REC") is developing where the tag or green traits of qualifying power production facilities can be detached and sold separately from the power itself. Generally, wind, solar, geothermal and some other resources qualify as renewable resources, although each state may have a slightly different definition. California and Oregon have renewable portfolio standards that limit the Company's ability to sell green tags. Therefore, this adjustment reverses actual sales and allocates the sales for the 12 months ended June 2009 to the remaining jurisdictions.

Clark Storage Revenues (page 3.7) – The Clark Storage & Integration Agreement was terminated in December 2007. This adjustment removes the revenue credit from the results of operations to reflect a normalized level of ancillary service revenues.

SO2 Emission Allowances (page 3.8) – Over the years the Company's annual revenue from the sale of emission allowances has been uneven. Consistent with the Commission order in Docket No. 97-035-01, the Company has amortized sales of emission allowances over a four-year period. In addition, this adjustment includes projected sales through June 2009. This adjustment replaces the sales from the historic period with the appropriate annual amortization.

Tab 4 – O&M Adjustments

Q. Please describe the information contained behind Tab 4 O&M Adjustments.

A. Tab 4 includes the O&M Summary followed by a numerical summary and the specific adjustments. The O&M Summary begins on page 4.0.1 with a brief overview of assumptions used to adjust operations, maintenance, administrative and general expenses. The numerical summary (pages 4.0.4 – 4.0.6) identifies each adjustment made to actual expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments made to O&M expense in Tab 4.

A. **Miscellaneous General Expense (page 4.1)** – This adjustment removes certain miscellaneous expenses that should have been charged below the line to non-regulated expenses. Various items are included that were identified for removal in the Company's rebuttal testimony in Docket No. 07-035-93, such as advertising expenses and non-regulated cost of the Company plane.

Non Recurring Expense Adjustment (page 4.2) – Accounting entries were made to expenses during 2007 that were non-recurring in nature or related to prior periods. This adjustment removes these items reducing total Company operating expense by $2.5 million. Details on the specific items in the adjustment can be found on page 4.2.1 of Exhibit RMP___(SRM-2).

Irrigation Load Control Program (page 4.3) – Incentive payments made to Idaho customers participating in the irrigation load control program were initially system allocated in unadjusted data. This adjustment corrects that allocation and assigns these costs directly to Idaho consistent with other demand side management ("DSM") programs.

Blue Sky (page 4.4) – This adjustment removes costs associated with the Blue Sky program that were initially included in regulated results. The Blue Sky program is designed to encourage voluntary participation in the acquisition and development of renewable resources. To prevent non-participants from subsidizing the program this adjustment removes administrative and other expenses directly associated with the program.

K2 Risk Management System (page 4.5) – The K2 Risk Management system was capitalized during calendar year 2006; however, the project was written-off in March 2007 because it was deemed not used and useful. This adjustment removes the O&M expenses of the project and also removes the loss on the disposition of the asset in account 421.

Generation Overhaul (page 4.6) – Consistent with the Company's rebuttal position in Docket Number 07-035-93, this adjustment normalizes generation overhaul expenses using a four year average methodology. Overhaul expenses from 2004 - 2007 are escalated to 2007 dollars using Global Insight indices and then those escalated expenses are averaged. For new generating units Currant Creek and Lake Side, the four year average is comprised of the overhaul expense projected during the first four years these plants are operational. The adjustment is calculated by subtracting the actual overhaul costs from the escalated four year averages.

Upper Beaver Hydro Removal (page 4.7) – On September 14, 2007, the Company sold the Upper Beaver hydro facilities to the city of Beaver, Utah. This adjustment removes the Upper Beaver O&M expenses and the loss on the sale of the property. No adjustment to rate base is necessary because the asset was removed from rate base prior to December 31, 2007.

Preliminary Coal Plant Expense (page 4.8) – The Company was planning to build three coal units: IPP unit 3, Bridger unit 5 and Hunter unit 4. On December 6, 2007, the Company announced that it would not pursue these projects. The preliminary expenses the Company incurred for these abandoned projects were written off to account 557. This adjustment removes these write-offs from the results of operations.

Rental Expense (page 4.9) – This adjustment removes rental expense of unused office space booked during 2007. It also corrects the allocation of sub-lease income and annualizes the sub-lease rental income for agreements entered into during 2007.

DSM Expenditure Removal (page 4.10) – Utah allows for recovery of DSM expenses through the system benefit charge ("SBC") tariff rider. This adjustment removes DSM costs in order to prevent a double recovery through the revenue requirement and the SBC.

Wage & Employee Benefit Adjustment (page 4.11) – This adjustment is used to compute labor-related costs for the Test Period. Later in my testimony I describe the Company's approach for calculating labor costs included in the case.

MEHC Transition Savings (page 4.12) – This adjustment removes the costs associated with employees leaving under the MEHC transition plan. It also reflects into results the future labor savings of eliminating positions. The deferral and amortization of MEHC transition costs were removed consistent with the Commission's order in Docket No, 07-035-04 issued January 3, 2008.

Incremental Generation O&M (page 4.13) – This adjustment adds incremental operation and maintenance expense for the Lake Side plant, Blundell bottoming cycle, and the Marengo wind plant which were placed into service during 2007. This adjustment also adds incremental O&M expenses for generating units that were not in service during the 12 months ended December 2007 but will be in service prior to the end of the Test Period.

This adjustment also includes the impact of funding provided by the Energy Trust of Oregon ("ETO") associated with the Goodnoe Hills wind plant in exchange for additional renewable energy credits allocated to Oregon customers after the first five years of operation. The amount of the funding included in the current case is $2,473,254 on a total Company basis. If Utah elects to displace the ETO funding, as described by Mr. Mark Tallman in Docket No. 07-035-93, then this amount will need to be added to the test period revenue requirement.

MEHC Affiliate Management Fee Commitment (page 4.14) – This adjustment complies with the MEHC acquisition commitment 38 which states:

> MEHC commits that the corporate charges to PacifiCorp from MEHC and MEC will not exceed $9 million annually for a period of five years after the closing on the proposed transaction.

MEHC anticipates that the corporate charge to the Company will remain at $9 million during the five year period. This adjustment removes the MEHC corporate charge portion of the escalation shown on page 4.15 to keep the annual charges at the commitment level.

Global Insight Escalation Indices (page 4.15) – This adjustment increases non-labor expenses for projected inflation through the Test Period. Increases are based on indices produced by Global Insight, which provide a detailed assessment of the electric market both historically and into the future. The Global Insight's indices used are based on electric utility costs for materials and services only, which exclude labor expense, according to the Uniform System of Accounts defined by the FERC for major electric utilities and major natural gas pipeline companies. Labor-related expenses were segregated from other non-labor-related expenses to be escalated separately as described later in my testimony.

Global Insight's indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses. The Global Insight study used to prepare this filing was the first quarter 2008 forecast, released April 17, 2008. Page 4.15.1 provides an overview of the development and use of Global Insight indices. The Company has also relied on Global Insight indices in rate cases in Oregon, California and Wyoming.

WECC Fees (page 4.16) – This adjustment includes an increase in fees for membership in the Western Electric Coordinating Council ("WECC"). WECC continues to be responsible for coordinating and promoting electric system reliability in the Western Interconnection, and its role has expanded into the compliance area, including enforcing auditing compliance standards, and supporting power markets and non-discriminatory transmission access among members.

Insurance Expense (page 4.17) – This adjustment normalizes injury and damage expenses to reflect a three-year average of gross expense minus insurance proceeds consistent with the Company's rebuttal position in Docket No. 07-035-93. This adjustment also normalizes property insurance expenses and captive property and liability insurance expenses.

Compliance Department (page 4.18) – As of June 18, 2007, the electric utility industry has been operating under mandatory, enforceable reliability standards. Utilities and other bulk power industry participants that violate any of the standards will face enforcement actions including increased compliance monitoring and testing requirements and/or possible monetary sanctions of up to $1 million per day. In order to comply with these enhanced reliability standards, the Company anticipates the addition of 13 full-time employees as well as increased program and information technology costs.

Solar Photovoltaic Program (page 4.19) – This adjustment reflects the estimated annual program costs associated with the pilot Solar Photovoltaic Utility Buy-Down Program co-sponsored by Utah Clean Energy and Rocky Mountain Power. This pilot solar photovoltaic project was implemented in September 2007 and is projected to operate at similar funding levels through

2011. The program will gather important information on the viability of a solar program funded by participating customers, tax incentives and utility contributions.

Q. Please describe how the Company computed labor costs for the Test Period.

A. The Company's adjustment to labor expense is found on Page 4.11, the Wage and Employee Benefit Adjustment. Labor-related costs for the Test Period are computed by adjusting salaries, incentives, benefits and costs associated with FAS 87 (pension), FAS 106 (post retirement benefits) and FAS 112 (post employment benefits) for changes expected beyond the actual costs experienced in 2007. Page 4.11.2 is a numerical summary starting with actual labor costs in 2007 and summarizing the adjustments made to project costs forward to reflect the Test Period level of expense. This summary is followed by the detailed worksheets used to adjust the labor costs forward to the Test Period.

The first step to adjust labor is to annualize salary increases that occurred during 2007. This was done by identifying actual wages by labor group by month along with the date each labor group received wage increases. Those increases were then applied to wages that were paid prior to the effective date. The next step is to apply the wage increases from 2008 through June 2009 to the annualized 2007 salaries to project the Test Period wages. The Company used union contract agreements to escalate union labor group wages, while increases for non-union and exempt employees were based on budgeted increases. This calculation is detailed on pages 4.11.3 through 4.11.5.

Q. Was an adjustment made to the annual incentive plan payout?

A. Yes. An adjustment is made to increase total Company incentive compensation from $29.9 million in 2007 to $30.9 million in the Test Period as shown on page 4.11.2. The Company utilizes an incentive compensation program as part of its philosophy of delivering market competitive pay structured in a manner that benefits customers with safe, adequate and reliable electric service at a reasonable cost.

Q. Were employee pension and benefit costs adjusted in this section also?

A. Yes. Consistent with the aforementioned costs, pension expense and other employee benefit costs were itemized starting with 2007 and walked forward to the Test Period. Total pension costs decrease by $27.9 million between 2007 and the Test Period. These projections were provided by Mr. Erich D. Wilson and are supported in his testimony.

Q. Were any other components of labor costs adjusted?

A. Yes. Payroll taxes were updated to capture the impact of the changes to employee salaries. This was calculated by applying the FICA tax rates to the net change in salaries and also to reflect the change in the social security cap for the Test Period.

Q. Did the Company make an adjustment for changes in workforce levels?

A. The wage and employee benefit adjustment assumes a constant level of workforce. However, other adjustments account for minor changes in workforce levels such as: 1) the labor savings from the reduction in the number of employees due to the MEHC transaction was reflected in the MEHC Transition Savings adjustment (adjustment 4.12), 2) the additional costs from the addition in compliance staffing as stated in the Compliance Department adjustment (adjustment 4.18), and 3) the labor savings from the reduction in workforce as a result of the Utah AMR included in adjustment 8.10.

Tab 5 – Net Power Cost Adjustments

Q. Please describe the information contained behind Tab 5 Net Power Cost Adjustments.

A. Tab 5 includes the Net Power Cost Summary followed by a numerical summary and the specific adjustments. The Net Power Cost Summary on page 5.0.1 is a brief overview of assumptions used to adjust overall net power costs. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **Net Power Cost Adjustment (page 5.1) –** The Net Power Cost adjustment normalizes steam and hydro power generation, fuel, purchased power, wheeling expense and sales for resale in a manner consistent with the contractual terms of the Company's sales and purchase agreements. It also normalizes hydro, weather conditions and plant availability as described in Mr. Duvall's testimony.

Green Tags (page 5.2) – This adjustment removes from regulatory results the cost of REC or green tag purchases made for the Blue Sky program.

West Valley Plant (page 5.3) – The Company terminated the lease for the West Valley generating facility on May 31, 2008. This adjustment removes the associated expense and rate base to align with net power costs which do not include the West Valley plant. Amortization of the savings from the reduction of the West Valley lease expense pursuant to MEHC transaction commitment U46 ends May 31, 2008; consequently, it has no effect on the Test Period.

James River Royalty Offset & Little Mountain (page 5.4) – On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the twenty-year operational term of the agreement as an offset to royalties paid to James River based on contract provisions. The contract costs of energy for the Camas unit are included in the Company's net power costs as purchased power expense, but GRID does not include an offsetting revenue credit for the capital and maintenance cost recovery. This adjustment adds the royalty offset to account 456, other electric revenue, for the Test Period.

This adjustment also normalizes the ongoing level of steam revenues related to the Little Mountain plant. Contractually, the steam revenues from Little Mountain are tied to natural gas prices. The Company's net power cost study includes the cost of running the Little Mountain plant but does not include the offsetting steam revenues. This adjustment aligns the steam revenues to the gas prices modeled in GRID.

Electric Lake Settlement (page 5.5) – Canyon Fuel Company ("CFC") owns the Skyline mine located near Electric Lake. Electric Lake is a reservoir owned by the Company and provides water storage for the Huntington generating plant. The two companies have disputed the claim made by PacifiCorp that CFC's mining operations caused the lake to leak water into the Skyline mine, thus making it unavailable for use by the Huntington generating plant. The Company has incurred capital costs and O&M costs to pump water from the breach back into Electric Lake. The two companies negotiated a settlement of the claims made by the Company. The settlement of costs includes reimbursement to the Company for O&M and capital costs associated with the pumping. The value of the settlement will be amortized over three years. This adjustment reduces rate base for the fixed cost portion of the settlement and includes the first year of amortization for the O&M portion of the settlement. This settlement also includes a new pumping agreement

Tab 6 – Depreciation and Amortization Expense Adjustments

Q. Please describe the information contained behind Tab 6 Depreciation and Amortization Adjustments.

A. Tab 6 includes the Depreciation and Amortization Summary followed by a numerical summary and the specific adjustments. The summary on page 6.0.1 is a brief overview of assumptions used to adjust overall depreciation and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit

RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. How are the Company's pro forma depreciation and amortization expense for the Test Period developed in the Report?

A. The depreciation and amortization expense for the Test Period is calculated by applying functional composite depreciation and amortization rates to projected plant balances. Rates used are those approved by the Commission in Docket No. 07-035-13, effective January 1, 2008. Details are provided on pages 6.1 through 6.1.13.

Q. How are the accumulated depreciation and amortization balances included in the filing calculated?

A. Accumulated depreciation and amortization balances for the Test Period are calculated by applying pro forma depreciation and amortization expense and plant retirements to the December 2007 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from December 31, 2007 to June 30, 2009. The reserve balance calculations are detailed on pages 6.2.2 to 6.2.11. Consistent with electric plant in service being reflected at period-end balances, accumulated depreciation and amortization also follow this same treatment.

Q. Please describe any additional depreciation adjustments included in the case.

A. **Hydro Decommissioning (page 6.3) –** Based on the Company's latest depreciation study approved in Docket No. 07-035-13, an additional $19.4 million is required for the decommissioning of various hydro facilities. This adjustment includes an annual level of expense in results, and the associated adjustment to the depreciation reserve is incorporated in adjustment 6.2.

Tab 7 – Tax Adjustments

Q. Please describe the information contained behind Tab 7 Tax Adjustments.

A. Tab 7 includes the Tax Summary followed by a numerical summary and the specific adjustments. The Tax Summary begins on page 7.0.1 with a brief overview of assumptions used. The numerical summary identifies each adjustment made to the various tax components and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 7.

A. **Interest True-Up (page 7.1) –** This adjustment details the adjustment to interest expense required to synchronize the Test Period expense with rate base. This is done by multiplying normalized net rate base by the Company's weighted cost of debt in this case.

Pro Forma Schedule M (page 7.2) – The Schedule M items at December 31, 2007 were updated for known and measurable adjustments through June 30, 2009. Non-utility items, separate tariff items and other non-recurring items were removed from the December 2007 historical period before updating. For example, Schedule M items related to the Grid West note receivable and West Valley Lease were removed. Normalizing adjustments such as pensions, benefits, and SO_2

emission allowances were then added. The Schedule M items were also adjusted for the Electric Lake settlement and depletion. Depreciation differences on capital additions were generated in order to bring the Schedules M items in line with the Test Period. The Schedule M items were then used to develop deferred income tax expenses and balances for the Test Period.

Deferred Income Taxes (page 7.3 & page 7.4) – The non-property-related Schedule M items were used to develop the deferred income tax expense. The property-related deferred income tax expense was generated using the capital additions and resulting book and tax depreciation. Normalizing adjustments were added consistent with the Schedule M items as described above. The deferred income tax expense was then used to develop the deferred tax balance for the Test Period.

Property Tax Expense (page 7.5) – Property tax expense for the Test Period was computed by adjusting accruals through December 31, 2007, for known or anticipated changes in assessment levels through June 30, 2009.

Renewable Energy Tax Credit (page 7.6) – The Company is entitled to recognize a federal income tax credit as a result of placing wind generating plants in service. The tax credit is based on the generation of the plants, and the credit can be taken for ten years on qualifying property. Under the calculation required by Internal Revenue Service Code Sec. 45(b)(2), the most current renewable electricity production credit is 2.1 cents per kilowatt hour of the electricity produced from wind energy.

Q. How have current state and federal income tax expenses been calculated?

A. Current state and federal income tax expenses were calculated by applying the applicable tax rates to the taxable income calculated in the Report. State income tax expense was calculated using the state statutory rates applied to the jurisdictional pre-tax income. The result of accumulating those state tax expense calculations is then allocated among the jurisdictions using the Income Before Tax (“IBT”) factor. Federal income tax expense is calculated using the same methodology that the Company uses in preparing its filed income tax returns. The detail supporting this calculation is contained on pages 2.18 through 2.20.

Q. Is the Company proposing to move to full normalization of book basis differences for taxes in this rate case?

A. No. The Company’s deferred income taxes in this case are calculated using 40 percent normalization of the book basis differences consistent with prior treatment of those items. However, the Company still believes that full normalization is the better approach and should be adopted by this Commission for future treatment of the book basis differences in subsequent rate filings. The Commission previously accepted a transition to full normalization through a phase in approach with 20 percent adjustments in each rate case to arrive at full normalization. The current level of book basis normalization is 40 percent due to the transition in two prior rate cases.

Q. Please explain full normalization and why it better reflects tax costs.

A. Full normalization is the concept of providing deferred tax expense to completely offset all book and tax timing difference occurring in current tax expense. The term “normalization” evolved with respect to utilities because income taxes computed on the normalization basis caused reported net income to appear “normal”, as if the utility had not adopted a tax return method of calculating its tax expense. Full normalization is more properly cost-based for ratemaking purposes than flow-through, because it more equitably allocates tax costs over time and treats customers fairly by not creating intergenerational inequities.

Q. What is flow-through?

A. Flow-through is the term used for passing through in the current period the impact of book and tax timing differences to income, with no offset of deferred tax expense.

Q. Do the Company’s books reflect full normalization in Utah?

A. Presently, the only portion of timing difference that do not have 100 percent deferred tax expense provided are the book basis differences related to depreciable property. The book basis differences only have 40 percent of deferred taxes normalized.

Q. Is the Company proposing moving to full normalization?

A. Yes. The Company believes that full normalization is the best method and should be used by the state of Utah. To give parties time to thoroughly review the issues, and to make a smooth transition, the Company is not making any changes in this rate case, but proposes the Commission reaffirm the prior treatment allowing the Company to move from 40 percent normalization to full normalization over time. The Company proposes that the Commission allow the Company to move to 60 percent normalization with the effective date of its next rate case, and 20 percent in each of the subsequent two rate cases on their effective dates.

Tab 8 – Rate Base Adjustments

Q. Please describe the information contained behind Tab 8 Rate Base Adjustments.

A. Tab 8 includes the Rate Base Summary followed by a numerical summary and the specific adjustments. The Rate Base Summary begins on page 8.0.1 with a brief overview of assumptions used to adjust electric plant in service and other rate base components. The numerical summary (pages 8.0.4 – 8.0.5) identifies each adjustment made to actual rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe each of the adjustments to the historical rate base balances.

A. **Cash Working Capital (page 8.1) –** This adjustment supports the calculation of cash working capital included in rate base based on the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on a lead lag study recently prepared by the Company using calendar year 2007 information. A copy of this study is being provided in this case along with the responses to the master data requests. Based on the results of the 2007 lead lag study, the Company experiences 6.2 net lag days in Utah requiring a cash working capital balance of $25.4 million to be included in rate base.

Goose Creek Transmission (page 8.2) – On April 1, 2008, the Company sold its undivided interest in 13.85 miles of transmission line, running from the Company's Goose Creek switching station and extending north to the Decker 230 kV substation near Decker, Montana. In addition to the radial transmission line, the assets sold included structures and miscellaneous support equipment, easements and rights-of-way associated with the transmission line. The sale of the transmission line resulted in the Goose Creek switching station no longer being needed or useful to the Company. In the summer of 2008, the Company plans to remove the Goose Creek switching station including all equipment, structures, slabs and other above ground facilities and level the site. After removal of the switching station, the Company will build a short segment of 230 kV transmission line to ensure continued operation of its Sheridan to Yellowtail 230 kV transmission line. This adjustment amortizes the net gain associated with the sale over three years, reduces rate base by the net book value of the assets sold and adds the new Yellowtail line into rate base.

Environmental Settlement – PERCO (page 8.3) – In 1996, the Company received an insurance settlement of $33 million for environmental clean-up projects. These funds were transferred to a subsidiary called PacifiCorp Environmental Remediation Company ("PERCO"). This fund balance is amortized or reduced as PERCO expends dollars on clean-up costs. PERCO received an additional $5 million of insurance proceeds plus associated liabilities from Rocky Mountain Power in 1998. This adjustment includes the unspent insurance proceeds in results of operations as a reduction to rate base.

Customer Advances for Construction (page 8.4) – Customer advances were recorded in December 2007 unadjusted data to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation of customer advances.

Customer Service Deposits (page 8.5) – Utah requires the Company to include customer service deposits as a reduction to rate base. This adjustment reflects the deposits in results as a rate base deduction and also includes the interest paid on the customer service deposits in expense. This treatment was stipulated in Utah Docket No. 97-035-01 and has been upheld in subsequent dockets.

Trapper Mine Rate Base (page 8.6) – The Company owns a 21.4 percent share of the Trapper Mine, which provides coal to the Craig generating plant. This investment is accounted for on the Company's books in account 123.1, investment in subsidiary company, which is not included as a rate base account. The normalized coal cost from Trapper Mine in net power costs includes O&M costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine net plant investment to rate base in order for the Company to earn a return on its investment.

Jim Bridger Mine Rate Base (page 8.7) – The Company owns a two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The Company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine investment is not included in electric plant in service.

This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base in order for the Company to earn a return on its investment. The normalized coal costs for Bridger Coal Company in net power costs include the O&M costs of the mine but provide no return on investment.

Miscellaneous Rate Base (page 8.8) – This adjustment includes four parts as described below:

- Cash is removed from rate base to avoid earning its rate of return on the balance.
- An anticipated increase in fuel stock is added due to increases in the cost of coal and the number of tons stored at each site.
- Regulatory assets and liabilities, including environmental assets, are adjusted to their Test Period balances.
- The accumulated provision for electric plant acquisition adjustment is adjusted to its Test Period balance.

Powerdale Hydro Removal (page 8.9) – Powerdale is a hydroelectric generating facility located on the Hood River in Oregon. This facility was scheduled to be decommissioned in 2010; however, in 2006 a flash flood washed out a major section of the flow line. The Company determined that the cost to repair this facility was not economical and determined it was in the ratepayers' best interest to cease operation of the facility.

This adjustment reflects the treatment approved by the Commission in Docket No. 07-035-14. During 2007, the net book value (including an offset for insurance proceeds) of the assets to be retired was transferred to the unrecovered plant regulatory asset. In addition, future decommissioning costs are deferred in a regulatory asset, offset by a credit reflecting the amount not actually spent through the Test Period.

Utah AMR (page 8.10) – The Company replaced approximately 600,000 meters on the Wasatch Front with new radio equipped digital meters. This change will allow the Company to reduce the number of meter reader positions by over 90 in this same area, resulting in a projected cost savings of over $3.4 million in the Test Period. This adjustment captures the savings due to the new automated meter reading program and reflects the associated asset retirements. The impact to depreciation reserve is captured in adjustment 6.2.

Pro Forma Plant Additions (page 8.11) – To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be completed by the end of the Test Period. Company business units identified capital expenditures that will be used and useful prior to the end of the Test Period. Additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Adjustment 8.13 is based on 13 month average balances, while adjustment 9.2 includes the additional rate base required to reflect capital additions on a year-end basis. The accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements as described earlier in the depreciation section.

Plant Retirements (page 8.12) – The Company's retirement rates were applied to pro forma plant balances included in this filing. This adjustment reflects these retirements into results.

Tab 9 –Test Period Adjustments

Q. Please describe the information contained behind Tab 9 Test Period Adjustments.

A. Tab 9 includes a summary of the miscellaneous test period adjustments followed by a numerical summary and each specific adjustment. The summary is on page 9.0.1 with a brief overview of assumptions. The numerical summary (page 9.0.2) identifies each adjustment and that its impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-2), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe each of the adjustments in Tab 9.

A. **Pro Forma Load Adjustment (page 9.1) –** This adjustment reflects the impact of updating load from the year ended December 2007 to the year ended June 2009. Retail revenue is adjusted to account for new load and net power costs are updated to reflect the cost to serve that load. In addition, the jurisdictional load is updated in the JAM model to produce new allocation factors and adjust the allocation of all system-wide costs.

End-of-Period Rate Base Adjustment (page 9.2) – This adjustment moves all rate base accounts from an average to an end-of-period basis as previously described in my testimony. References to previous adjustments treating the various rate base components are provided in support of the calculation.

Q. Please describe the rest of the Report.

A. Tab 10 Allocation Factors summarizes the derivation of the jurisdictional allocation factors using the Revised Protocol allocation methodology. Two sets of factors are provided with this case: one set based on weather-normalized actual load from 2007 and actual account balances ("Historical Factors"), and one set based on the load forecast through June 2009 and pro forma account balances ("Pro Forma Factors"). Printed lead sheets for individual adjustments and the various numerical summaries quantifying the impact of each adjustment show the allocation using the Historical Factors. Adjustment 9.1 updates all system-allocated costs based on the Pro Forma Factors.

Tab 11 Rolled-In recasts Tab 2 based on the Rolled-In allocation methodology. This information is being provided pursuant to the Commission order from the application of the Company for an investigation of inter-jurisdictional issues in Docket No. 02-035-04.

Q. Does this conclude your direct testimony?

A. Yes.