Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power ("Company").

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 explaining 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 Oregon Public Utility 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:

- Calculation of the $232.4 million requested rate increase.
- The test period utilized in this case, the 12 months ending June 30, 2012 ("Test Period").
- The inter-jurisdictional allocation methodology utilized to compute the requested price increase and the procedure that is currently ongoing before the Utah Public Service Commission ("the Commission") addressing inter-jurisdictional allocations.
- Support for the ongoing accounting for property and liability insurance expense and charges from MidAmerican Energy Holdings Company ("MEHC") for administrative services, two items addressed in MEHC merger commitments that are set to expire prior to the end of the Test Period.

- The Company's process for compiling the Test Period revenue requirement and a detailed explanation of the normalizing adjustments included in the case.

Revenue Requirement Summary

Q. What price increase is required to achieve the requested Return on Equity ("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, the 12 months ending June 30, 2012. At current rate levels Rocky Mountain Power will earn an overall ROE in Utah of 5.5 percent during the Test Period. This return is less than the 10.5 percent return recommended by Dr. Samuel C. Hadaway in this case. An overall price increase of $228.8 million would be required to produce the 10.5 percent ROE under the Revised Protocol allocation method. However, according to the stipulation approved by the Commission in Docket No. 02-035-04, a Rate Mitigation Premium applies in this case adding $3.6 million to the price change, for a total requested increase of $232.4 million.

Q. Please explain the Rate Mitigation Premium.

A. The Company's calculation of its Utah results of operations for the Test Period is based on the Revised Protocol allocation method as approved by the Commission in Docket No. 02-035-04. The stipulation approved by the Commission in that docket prescribes the method of calculating revenue requirement for setting rates along with certain rate mitigation measures. The stipulation states:

> 3. Rate Mitigation Premium
> Subject to the conditions of Paragraph 4b, below, for the period from April 1, 2009 to March 31, 2012, the Company may collect a Rate Mitigation Premium as follows: the Company's Utah revenue requirement as calculated pursuant to the Revised Protocol multiplied by 100.25 percent.[1]
>
> 4b. Unless and until any amendments to the Revised Protocol are ratified by the PSCU, 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: (i) 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, plus the Rate Mitigation Premium referenced in Paragraph 3, if applicable. [2]

In this case the Rate Mitigation Premium applies. As shown on page 1 of my Exhibit RMP___(SRM-1), Revised Protocol plus the Rate Mitigation Premium is the lesser of (i) and (ii) above. For purposes of this case the Company prorated the Rate Mitigation Premium of 100.25 percent to apply to nine months of the Test Period which ends June 30, 2012.

Test Period and Revenue Requirement Preparation

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

A. The Company projected results of operations for the period of time beginning July 1, 2011, and ending June 30, 2012. The Test Period utilizes an average (13 month) rate base with a historical base period of the year ended June 30, 2010.

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

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

Q. Why did the Company use the year ending June 30, 2012, as the Test Period?

A. The Company's primary objective in 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 the new rates will be in effect. Beyond satisfying this fundamental ratemaking principle, the Company also considered the Utah statutory constraints, issues addressed in previous regulatory proceedings, the current regulatory environment, and the need for transparency with customers and regulators. The Company's proposed test period in this case balances the need for adequate recovery of prudent costs with these other considerations.

Q. What business factors influenced the Company's choice of test period in this case?

A. Two main drivers are causing the need for a revenue increase in this case: net power costs and capital investment. As a regulated utility we must continue to incur these increased costs to meet our customers' growing demand for electricity and to improve service reliability.

Rocky Mountain Power is building new generation facilities, improving the efficiency and reducing the environmental footprint of existing generating plants, increasing the capacity of its transmission system, and building new distribution lines and substations. New facilities are significantly more expensive than similar facilities currently included in rates. The test period includes $2.2 billion more electric plant in service on a total Company basis and $1.2 billion more on a Utah-allocated basis than the previous case, adjusted for the major plant addition cases completed during 2010. On a Utah-allocated basis, total rate base in this case is over $340 million higher. Company witnesses Mr. Darrell T. Gerrard, Mr. Douglas N. Bennion, and Mr. Chad A. Teply provide support for investments in new facilities required to serve customers. As explained by Company witness Mr. Gregory N. Duvall, total Company net power costs are expected to rise from the $994.2 million set in the Docket No. 10-035-89 settlement to $1.521 billion in the Test Period.

Q. Has the Company been able to manage other costs of doing business that are within its control?

A. Yes. It is important to note that, on a per-unit basis, Utah-allocated non-net power cost operations, maintenance, administrative and general costs are lower than included in the 2009 general rate case.

Q. Why is the Company's Test Period necessary to represent the conditions when new rates from this case are in effect?

A. As described above, the Company is in an environment of rapidly increasing costs related to capital investment and changes in net power costs which emphasizes the need for rates to be set based on a test period that is closely synchronized with the rate effective period to adequately reflect conditions expected during the time rates will be in effect. Only a test period strongly aligned with the rate effective period can sufficiently capture the rate-making impacts of growing customer load, the capital investment required to serve it, and the operation and maintenance ("O&M") costs required to maintain system safety and reliability. If the rates in this case were set based upon outdated historical investment levels and costs, the Company would have no chance of being compensated properly for the service provided to customers and would not have a reasonable opportunity to earn the return authorized by the Commission.

Prices paid by consumers should be set at a level that matches contemporaneously the cost to provide service. A rate base, rate of return regulated utility like Rocky Mountain Power must be given a reasonable opportunity to recover its cost of service, and I believe that the Company's current circumstances are a perfect example of the need for the Test Period in this case.

Q. Why is a forward-looking test period necessary?

A. Robert Hahne, in his book *Accounting for Public Utilities*, states that "[T]he test period, by nature and by design, is a surrogate for conditions of the period of rate use and, to repeat, is presumed to be representative of future conditions." (7-11, Section 7.06.) This objective is captured in Section 54-4-4(3)(a) of the Utah Code which states:

> If in the commission's determination of just and reasonable rates the commission uses a test period, the commission shall select a test period that, on the basis of evidence, best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect.

Ordered rate changes in general rate cases become effective at the end of the statutory 240-day period provided under section 54-7-12(3) of the Utah Code. Based on the anticipated filing date of the full revenue requirement in this case, January 24, 2011, new rates will become effective on or before September 21, 2011. A forecast test period allows for better matching of costs with revenues during the rate-effective period. In order for rates to be based on costs to support the financial integrity of the Company, it is essential to have rates set on costs that reflect the time period that the rates will be in effect.

A forecast test period is fundamental during a period of major construction and/or rising expenses. In the current environment, a future test period best reflects 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 load growth to continue to be an issue in the Utah service territory over the long term. Planning to serve growing load requires the Company to acquire new generating resources. Significant new investments in transmission and distribution systems are required to integrate these new resources, connect new customers and ensure continued reliability. During this period of increased capital investment and rate base growth, a historical or near term forecast test period cannot adequately capture the conditions that the Company will experience during the rate-effective period; rather, use of a historical test period or a near term forecast test period would understate the true cost of service.

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

A. "Regulatory lag" refers to the time difference between when costs are incurred and when they are included in rates. More than anything else, regulatory lag can be 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. Basing rates on a test period that doesn't reflect the true costs to serve customers during the rate-effective period gives poor price signals to customers while also effectively denying the Company a reasonable opportunity to recover the costs of providing service, including the opportunity to earn the return on investment authorized by the Commission.

Q. Why did the Company choose the year ending June 30, 2012, as the Test Period?

A. As previously discussed and as allowed by statute, 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 on Test Period issued February 14, 2008 in Docket No. 07-035-93, the Commission also expressed its desire to balance Company and ratepayer interests. The Company is proposing the Test Period in this case after consideration of the current regulatory environment, Utah statutes governing test period development, and the factors identified above by the Commission.

[3] Order Approving Test Period Stipulation, Docket No. 04-035-42 (October 20, 2004); Order on Test Period, Docket No. 07-035-93 (February 14, 2008).

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 –** While inflation is not one of the major drivers of this rate case, inflationary pressures still remain and must be reflected in test period cost projections. The Company is striving to absorb cost increases as much as possible, and has managed to keep non-NPC O&M expenses flat compared to the last Utah general rate case on a $/MWh basis. However, the Company will still experience inflationary cost increases along with other increases such as labor costs due to negotiated increases in many of its union labor contracts.
- **Changes in Utility Investment, Revenues, and Expenses –** The Utah service territory continues to grow and long term load growth is expected to continue. Because of past, current, and future 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. The impact of the Company's capital expenditure program will continue to put pressure on the Company's earnings even with the use of forecasted test periods.

  This case includes Utah's portion of approximately three billion dollars in new plant investments the Company has made or will make between the July 1, 2010 and June 30, 2012, the end of the Test Year. In addition, because of the use of June 30, 2010 average rate base in the last general rate case, the Company has not included all of the capital investments from July 1, 2009 through June 30, 2010 in Utah rates. In addition, although the Company was allowed to add the Dave Johnston Unit 3 Scrubber, Dunlap I wind plant and the Populus to Terminal transmission line in rates as major plant additions, the Company has made a significant amount of smaller capital additions since July 1, 2010 that are not included in customer rates. The failure to include these investments in rates understates the cost of serving customers and puts significant financial pressure on Rocky Mountain Power. I will provide a more detailed description of the current and projected major capital projects later in my testimony.

- **Changes in Utility Services –** No change in service levels is anticipated, however the Company continues to fund maintenance to allow for the provision of safe and reliable electric service and meet our merger commitments.
- **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 a significant amount of information along with this filing as part of the Commission's filing rules. During this general rate case the Company is committed to responding to additional data requests from the parties in a timely manner.

Other parties have suggested in prior cases that the most important criteria for test period selection is the accuracy of the data or forecasts during the test period. If this suggestion is taken to its logical extreme, it would always require the use of a historic test period because data from a historic test period is always going to be more accurate than data from a forecast test period. However, such a conclusion misses the point. As Dr. Alfred Kahn noted years ago,

> The fact is … regulatory commissions have always been in the business of projecting, whether they knew it or not. When they used historic test year statistics, fully verifiable and verified, graven in stone, as the basis of future rates, they were in fact projecting. They were assuming that the future would be similar to the past. It is no more speculative, then, to make the best possible estimate of future costs when setting future rates; and honesty compels it.[4]

The issue is not that data for a historic test period may be audited or may be certain. The issue is whether the data for the historic test period is a better predictor of the rate-effective period than a forecast for that period.

- **Ability to Synchronize the Utility's Investment, Revenues, and Expenses**

The synchronization or "matching" of a utility's revenues, expenses and investments in setting rates is a traditional rate making concept; however, it is one that cannot be viewed in isolation without taking into consideration the rate-effective period. The goal in setting rates should be to set rates that properly reflect the costs that will be incurred by a utility during the period that the rates will be in effect. If the rate-effective period is not considered, then the process of matching revenues, expense and investments may capture interdependent impacts, but the result may not reflect the costs to be incurred during the rate-effective period. For example, a test period based on purely

[4] A. Kahn, "Between Theory and Practice: Reflections of a Neophyte Public Utility Regulator," *Public Utilities Fornighty* 29 (Jan. 2, 1975).

historical information may be properly synchronized between the revenues, expenses and investments included in the test period, but may have very little to do with the costs that will be incurred when new rates go into effect. When the test period does not properly match the rate-effective period, other regulatory tools have been used to adjust the test period to reflect the proper level of costs to be considered in new rates, including, year-end rate base, known and measurable adjustments (often one-sided, non-matching adjustments), and budget levels.

The Company is using a 13 month average rate base for the test period. The Company believes this is appropriate in this case because the test period corresponds quite closely with the first year of the rate-effective period. The rate-effective period is likely to start about 80 days after the start of the test period.

The important synchronization under the statute is synchronization between the revenue requirement determined for the test period and the costs that will be incurred during the rate-effective period. Notably, section 54-4-4(3)(a) requires the Commission to select a test period that best reflects the conditions that a utility will encounter during the rate-effective period. The purpose of using a test period is simply to attempt to predict the costs that the utility will incur during the rate-effective period. Synchronization of revenues, expense and rate base is only helpful if it achieves that end.

As previously mentioned, the most important element of matching is that the test period should reflect the costs that the Company expects to incur during the rate-effective period. As stated in *Accounting for Public Utilities* by Robert L. Hahne "If the period forecasted coincides with the period in which the new rates will be in effect, the matching of investment levels to operating results should produce the earnings levels authorized". (Hahne 7-5, Section 7.04).

- **Whether the Utility is in a Cost Increasing or Cost Declining Status –** As discussed above, while there is minimal pressure associated with increasing O&M costs, as a result of its capital investment program and changes in net power costs the Company is in a rising cost environment. This is discussed in greater detail later in my testimony and in the testimony of Mr. Duvall.
- **Incentives to Efficient Management and Operation –** The Company management is continually looking for ways to increase the efficiency of the Company. 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 in these efforts.

Some parties have argued that regulatory lag provides an incentive for management efficiency because it forces management to cut costs in order to have the opportunity of recovering the Company's true costs of providing service to customers when rates are based on a period prior to the rate-effective period. The circular logic of this argument is dubious in any circumstances, but is particularly dubious in the context of a case in which the rate increase is sought to recover the costs of new investments which are necessary to provide reliable service to customers. The incurrence of prudent costs of major capital resources cannot be reduced by management efficiency.

- **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. This factor is best satisfied by setting rates that are expected to recover the true costs of providing service during the first full year that new rates are in effect.

Q. Should each of these factors be given equal weight by the Commission?

A. No. Certain factors will be more important at a given point in time than other factors. In this case, changes in utility investments should be given predominant weight

Q. What are the primary drivers of this case?

A. The main drivers for this general rate case are the significant level of capital investment the Company is making on behalf of our customers and increases in the Company's net power costs. As mentioned earlier in my testimony, Company witnesses Mr. Gerrard, Mr. Bennion, and Mr. Teply provide support for investments in new facilities required to serve customers, and Mr. Duvall provides testimony on net power costs

Q. Given the level of capital investments, what would be the impact of choosing a test period that ends earlier than the Test Period proposed by the Company in this case?

A. Using a test period that ends earlier than June 2012 would assure that customers will not pay and that the Company will not recover its actual costs of providing service during the rate-effective period. As I have previously testified, one of the drivers for this rate case is the capital investments the Company has made and will be making through June 30, 2012.

Q. What is the most appropriate test period to use in this case?

A. The Company's proposed 12 months ending June 30, 2012 test period is the Test Period that is most likely to represent conditions during the period the rates set in this case will be in effect. The major driver of the Company's need for a rate increase is the capital investments the Company has made and will make through June 2012 and changes in net power costs required to serve our customers. These increases must be included in rates if the Company is to have a reasonable opportunity to recover its costs of providing service to customers including a reasonable return on its investments.

Q. Did the Company prepare the Alternative Period as required in Utah Rule R746-700-10.A.2?

A. Yes. In compliance with that rule, the Company has provided normalized results of operations for the 12 months ending June 30, 2011 ("Alternative Period"), which is the closest of June or December following the filing date of this application.

Q. Should the Alternative Period be relied on to set rates in this case?

A. No. The alternative period will be concluded over two months prior to the implementation of any rate changes related to this case. Therefore, the use of the alternative period would result in the use of historical information at the time rates are updated, and would reflect a step backwards in setting Utah rates.

On January 1, 2011 rates were changed in Utah in Docket No. 10-035-89 for the major plant additions made by the Company for the Populus to Ben Lomond Transmission Line and the Dunlap I Wind Project. However, in the July 1, 2010 to June 30, 2011 Alternative Period neither of these investments is completely included due to the use of average rate base. These two major plant additions are in-service, providing benefits to Utah customers, and are already included in Utah rates. It would be illogical and contrary to the intent of the major plant addition statute to use a test period that partially removes from rate base major plant additions that are already in-service and included in rates.

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 12 months ended June 30, 2010. Each of the revenue requirement components in that historical period was analyzed to determine if an adjustment would be 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. Exhibit RMP___(SRM-2) provides a summary index identifying each normalizing adjustment and where each adjustment is addressed in the Company's filing.[5]

[5] In conformance with filing requirement R746-700-10.A.1.c.

Q. Is the development of the Test Period in this case consistent with that of the Company's previous general rate cases in Utah?

A. Yes.

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 participants involved 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 results of operations.

A. Historical retail revenue is first adjusted to reflect normal weather conditions and remove 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. Peter C. 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 projected price changes using nationally-recognized inflation indices provided by IHS 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. Rate base was adjusted to capture planned additions to electric plant in service and known changes to other rate base items. In addition, asset retirements and accumulated depreciation were walked forward through the end of the Test Period based on composite retirement and depreciation rates by plant function. 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. How has the Company addressed areas where the expected change in O&M is different than the price changes projected by IHS Global Insight?

A. The Company's business units provided regulation with insight into costs that may be changing in the future due to causes other than inflation and also provided support for specific changes in the number or frequency of activities which would drive changes in costs. Examples of these types of adjustments are the Utah Automated Meter Reading ("AMR") Program adjustment (Adjustment 4.13) which reflects efficiencies from automated meter reading projects, and the Incremental Generation and Transmission O&M adjustment (Adjustment 4.15) which includes the cost of operating and maintaining new plants as well as changes in costs at some existing facilities. These adjustments are necessary because inflation indices are applied to costs for existing units of production which will not capture changes in volume or processes.

Inter-Jurisdictional Allocations

Q. What methodology did the Company use to calculate the Utah-allocated revenue requirement in this case?

A. The Company's requested price increase is calculated using the Revised Protocol allocation method as approved by the Commission in Docket No. 02-035-04. According to the terms of the stipulation approved previously in that Docket, "PacifiCorp agrees that, until such time as the Revised Protocol is amended in accordance with its terms, all general rate case filings made by it in Utah, subsequent to PSCU ratification of the Revised Protocol, will be based upon the provisions of the Revised Protocol."[6] The Company recently proposed modifications to the Revised Protocol in an application filed with the Commission also under Docket No. 02-035-04; the revised methodology is called the '2010 Protocol.' The 2010 Protocol contains proposed amendments to the Revised Protocol based on collaboration with multiple stakeholders through the multi-state process ("MSP") Standing Committee, the group tasked with evaluating the continued use of the Revised Protocol for setting rates. For comparison purposes the Test Period results for this case in Exhibit RMP___(SRM-3) are provided using Revised Protocol, 2010 Protocol, and Rolled-In.

Q. What is the status of the Company's application in Docket No. 02-035-04?

A. The Company's application was filed with the Commission on September 15, 2010, and is currently pending before the Commission. Interested parties are

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

working toward a possible settlement agreement, and testimony is scheduled to be filed on February 23, 2010, if a settlement is reached.

Q. What are the direct impacts on this case related to the 2010 Protocol?

A. Compared to the Revised Protocol there are three main impacts in this case. First, the scope of the Embedded Cost Differential ("ECD") is reduced and is now a fixed amount rather than allowed to change with each set of results. Second, seasonal allocation of certain resources is eliminated. Third, state income taxes are calculated for each jurisdiction using the weighted statutory state tax rate rather than allocated using the Income Before Tax ("IBT") allocation factor. Overall, using the 2010 Protocol reduces Utah-allocated revenue requirement in the Test Period when compared to the Revised Protocol. Tab 10 of Exhibit RMP___(SRM-3) provides the test period results using the 2010 Protocol allocation methodology for comparison purposes.

Q. Does the Company intend to reflect the outcome of its application in Docket No. 02-035-04 in this case?

A. Yes. The Company intends to include in this case any Test Period impacts related to any Commission-approved outcome in that Docket.

Q. Are there any other allocation related issues that have been raised outside of the Company's 2010 Protocol filing?

A. Yes. The Company also has a general rate case under way in Idaho and is anticipating a final order in February. Parties to that case have raised the issue of system allocating the costs and benefits related to Idaho's Irrigation Load Control program, currently classified as a class 1 demand-side management ("DSM") program. The Idaho irrigation program provides the Company with over 200 MW of irrigation load curtailment during June, July, and August. In Utah, the Cool Keeper DSM program provides the Company with approximately 100 MW of air conditioning load curtailment during the summer months. These programs and other smaller programs are currently classified as DSM for allocation purposes, meaning the load reductions are reflected in jurisdictional loads for allocation and the program costs are situs assigned to the individual state. Parties to the Idaho case have recommended that the Idaho Irrigation Load Control Program be system allocated rather than situs assigned. The Company will continue to work with those parties, as well as interested parties in Utah, to ensure resolution of the issue that is acceptable to all states. The Company's filing in this Docket continues to assign these DSM programs on a situs basis, but an adjustment may be required in this case to reflect any accepted changes.

Insurance Expense

Q. Please explain the Company's proposed treatment of property and liability insurance.

A. In this case the Company is proposing to replace its current captive insurance policy with self insurance coverage for third-party liability, transmission and distribution ("T&D") property, and non-T&D property. The Company's proposal eliminates the expense for captive insurance premiums and instead provides an accrual to self-insurance reserves. These self insurance reserves will cover O&M related damages. Capital related damages will be recovered as projects are added to rate base, consistent with other capital investments.

Q. How has insurance coverage for these three categories been provided since the acquisition of PacifiCorp by MEHC?

A. Since the MEHC acquisition the Company has utilized a captive insurance company to provide property and liability insurance. Commitments specific to states other than Utah limited premiums paid to the captive insurance company to $7.4 million annually, on a total Company basis, and the Company has limited the captive insurance premiums in rates at that level. In March 2010 the captive insurance policy was renewed for one additional year, but the commitment to utilize a captive insurance company with limited premiums expired December 31, 2010.

Q. What level of coverage was provided by the captive insurance?

A. The coverage under the captive varies by category:

- Excess liability insurance provides indemnity for amounts the Company is legally obligated to pay for damages due to bodily injury, personal injury or property damage. The captive covers $750,000 per occurrence, in excess of a $250,000 deductible. Commercial insurance covers $175.0 million per occurrence after a deductible of $1 million.
- T&D property damage insurance covers property damage to overhead transmission and distribution lines related to both O&M and capital events. The first $25,000 damages per event are defined as a deductible and are allocated to O&M and capital. The captive then covers $10.0 million annually in excess of an annual $5.0 million aggregate deductible (over and above the $25,000 per-event deductible). There is no

commercial insurance for T&D property damage.

- Non-T&D property damage covers all risks of direct physical loss or damage including boiler explosion, machinery and electrical breakdown, flood and earthquake. The captive covers $6.0 million per occurrence, in excess of a $1.5 million deductible. Commercial insurance covers $400 million per occurrence after a deductible of $7.5 million.

Q. When will the policy change from captive insurance coverage to self insurance be implemented?

A. The Company's proposed treatment would take effect after the current captive coverage expires on March 21, 2011. Coverage currently provided by commercial carriers will continue, and the related premiums are included in this case at actual levels. The Test Period in this case includes a full year of the new accounting for self insurance accruals.

Q. What will be the new level of coverage?

A. The initial deductible for each storm or casualty O&M event damaging distribution property will be raised from the current level of $25,000 to $250,000. The deductible for O&M transmission and non-T&D property damages will be $1 million per event. O&M related damages for all costs up to these deductible limits will be charged to the proper functional O&M FERC account. Amounts exceeding these deductible limits will be charged to the accumulated insurance reserve. There will be no deductible amounts applied to capital projects.

Q. Please describe the Test Period treatment of third-party liability insurance.

A. As shown on page 4.11.2 of Exhibit RMP___(SRM-3), captive insurance premiums and coverage are assumed only through March 21, 2011. For the Test Period self-insurance accruals replace the captive premiums. The level of the self-insurance accrual is a three-year average of liability claim payments by MEHC captive insurance from July 2007 through June 2010. Utah's allocated portion of the test period amount is based on the System Overhead ("SO") factor. The injuries and damages expense the Company incurs in addition to the amount currently covered by the captive are included based on a three-year average of the cash paid net of insurance reimbursements, consistent with the Company's previous general rate cases in Docket Nos. 08-035-38 and 09-035-23.

Q. Please describe the treatment of property insurance in the Test Period.

A. As shown on page 4.11.3 of Exhibit RMP___(SRM-3), captive insurance premiums and coverage for T&D and non-T&D property are assumed to be in place only through March 21, 2011. For the Test Period, self insurance accruals are included using a three-year average of actual damages from April 2007 through March 2010. Damages are included only to the extent they exceed the revised deductibles by category. The allocation of accruals and actual storm or casualty costs will be consistent with the allocation of similar types of electric plant in service (i.e. distribution is situs assigned and transmission and non-T&D are allocated on the SG factor).

Due to the increase in deductible limits, expenses for property damages that are currently classified as insurance expense are effectively being transferred to O&M. Page 4.11.4 shows that the increase in deductible limits reduces the amount of storm or casualty events that would be covered by the insurance reserve. Costs not covered by the insurance reserve would need to be covered by the Company's ongoing O&M. The Company has included the effect of this transfer as an O&M expense of $4.5 million in the Test Period in order to set rates at a level that will adequately cover expected storm and casualty damage.

Q. Please describe the accounting entries that will be booked once self insurance coverage begins.

A. Page 4.11.5 of Exhibit RMP___(SRM-3) shows an example of the accounting entries to be made in the future based on the Company's proposal in this filing. Each month, debits will be made to FERC accounts 924 – Property Insurance and 925 – Liability Insurance, with the corresponding credits booked to insurance reserves in FERC account 228. Separate internal accounting orders will be used for the reserve balances to track the state-specific amounts associated with the liability and property balances. When the Company experiences an insurance event, the reserve balance will be debited and cash or accounts payable will be credited to pay for the damages incurred allocated to Utah using then-current allocation factors. If the Company experiences events in excess of the accumulated reserve balance, or anticipated reserve balance through the remaining portion of each calendar year, the Company will accumulate these amounts as a regulatory asset until such time as the allowed annual accrual amount covers such losses or specific recovery for an event is requested and approved.

Q. What is the impact of the Company's proposal on Utah customers in this case?

A. Overall the Company's proposal results in an increase in costs allocated to Utah compared to the actual costs in the year ended June 2010. Page 4.11 of Exhibit RMP___(SRM-3) shows the Utah-allocated impact of the adjustments for both liability and property insurance. The net expense for Utah-allocated liability insurance increases approximately $290,535. Utah-allocated property insurance expense is reduced by over $3.5 million, but is offset by O&M expense of approximately $4.5 million.

MEHC Administrative Services

Q. Please explain the Company's proposed treatment of charges for MEHC administrative services.

A. Since the MEHC acquisition, the corporate management fee billed to PacifiCorp has been capped in accordance with 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.

This commitment expires March 21, 2011, prior to the Test Period in this case. Charges for the Test Period are based on the actual amount booked in the year ended June 30, 2010, after adjusting for amounts that should have been booked below the line.

Q. What is the result of the Company's proposed treatment?

A. The net impact of the Company's adjustment is to reduce the expense for MEHC administrative services in this case to approximately $7.0 million, or about

$500,000 less than the amount included in regulated expenses in the year ended June 30, 2010. Page 4.4.1 of Exhibit RMP___(SRM-3) provides additional details regarding the charges included in results.

Q. Is there an agreement filed with the Commission that governs the terms and conditions for MEHC administrative services to PacifiCorp?

A. Yes. The MEHC inter-company affiliated services agreement ("IASA") governs these services. In merger commitment 13 the Company agreed to file the IASA with the Commission. The Company made this filing on March 31, 2006, and it was approved by the Commission in October, 2006.

Q. Please describe the types of charges for MEHC administrative services governed by the IASA.

A. There are two kinds of charges assigned for MEHC administrative services, direct charges and allocated costs.

Direct charges are those costs where the employee performing the service is working directly for or on behalf of the Company. Examples of these types of charges would include, among other things, participation in Company specific meetings, negotiations on behalf of the Company or performing individual tasks related solely to the Company. The party receiving the benefit of the services provided is charged for the operating costs incurred by the party providing the service.

Allocated charges are for costs incurred for the general benefit of the entire corporate group or multiple segments including the Company for which direct charging is not practical. These include costs where the Company is receiving benefits through joint participation in the larger group. Examples include, among other things, senior management oversight of common functions such as human resources, environmental, information technology and finance. An allocation methodology is established to assign these charges fairly and is used consistently from year to year.

Q. Does MEHC charge out all of it costs?

A. No. For example, in the year ended June 30, 2010 MEHC charged out only 46 percent of its labor costs. Of this amount, the Company received 35 percent. In other words, the Company only received approximately 16 percent of the total labor charges at MEHC.

Q. Have the services provided to the Company under the IASA permitted the Company to substantially reduce its administrative and general costs?

A. Yes. Prior to the IASA, for the 12 months ended March 31, 2006, administrative and general costs totaled $248 million on a total company basis. For the Test Period in this case administrative and general costs total $161 million including the IASA charges.

Q. Please describe how the Company uses its participation in the IASA to the benefit of its customers.

A. The IASA provides the Company with a range of services, including executive leadership, strategic management and planning, financial planning and analysis, insurance, environmental compliance, financial reporting, human resources, legal, accounting and other administrative services, at a fraction of the cost it would otherwise incur for such services. Because of the IASA, there are several major

PacifiCorp business departments where the highest ranking employee is at the director level, including information technology, human resources, and environmental services. These directors report to MEHC management and, in turn, PacifiCorp is charged only a fraction of the total costs for these senior MEHC management positions. The Company believes that this is an efficient and effective way to manage the business and help control costs.

Q. How does the Company benefit from using other MEHC subsidiary employees to provide some services to the Company versus using outside contractors?

A. MEHC and its subsidiaries' staff are very experienced in dealing with the Company's business needs given their extensive background in working with U.S. regulated businesses. For example, MEHC corporate staff is well versed in dealing with Federal Energy Regulatory Commission, North American Electric Reliability Corporation, and U.S. Securities and Exchange Commission matters. In addition, MEHC has a consistent program of establishing salaries for employees across all of its platforms and a consistent overarching employee business expense policy. This consistency provides assurance that when employees from other platforms provide services under the IASA, the Company is obtaining the same benefit as if the work was performed by one of its employees. This allows PacifiCorp to have access to a broader population of expertise when dealing with specific issues on a direct cost basis.

Q. Please provide examples of where the Company has received benefits from belonging to the larger MEHC organization.

A. The MEHC corporate management style emphasizes prudent cost management. This has resulted in direct savings to the Company's customers both through lower costs and higher benefits. For example, the Company's audit fees are lower since the MEHC transaction. The current hourly rate is $162 per hour, as compared to a rate of over $216 per hour prior to the transaction.

Settlement Fees

Q. Please describe your Exhibit RMP___(SRM-6).

A. In the revenue requirement Order in Docket No. 09-035-23, page 87, the Commission directed the Company to provide a summary exhibit detailing actual settlement fees for the past five years and proposed test year settlement fees. In compliance with that order, Exhibit RMP___(SRM-6) contains a five-year history of settlement fees, by FERC account and allocation factor, for the 12 months ended June 30, 2006 through June 30, 2010. This exhibit also includes details of the settlement fees included in the June 2012 test year, which are the June 30, 2010 settlement fees escalated for inflation through June 30, 2012, resulting in $129,144 on a total Company basis in the Test Period.

Q. Please describe the process by which this exhibit was prepared

A. Exhibit RMP___(SRM-6) was prepared by summarizing on a mid-year basis all transactions posted to the Company's settlement fees accounts 545500 and 545501 over a period of five years, from July 1, 2005 to June 30, 2010. The related FERC account assignments are derived by the location and cost center charging the cost. Figures for all mid-years are reflected at an unadjusted Total Company level. Test Year June 2012 results are also reflected on a total company level including escalation. This exhibit excludes settlement fees that have been charged to accounts below the line that are not included in this filing, as well as those charged to capital. Additionally, it omits any Injuries and Damages settlements, as these are normalized to a three year average in Adjustment 4.11 – Insurance Expense in Exhibit RMP___(SRM-3).

Q. Were there adjustments made to the unadjusted data summarized in Exhibit RMP___(SRM-6)?

A. Yes, the 'Adjustments' section within RMP Exhibit___(SRM-6) is broken up into two sections. Section I outlines adjustments made to the base year in Adjustment 4.3 of Exhibit RMP___(SRM-3). Net of adjustments and including escalation, the total settlement fee balance for test year ending June 2012 is $129,114. Section II provides a summary of prior year adjustments made in prior Utah filings including general rate cases or Semi-Annual Results of Operations reports. These adjustments are shown as a measure of providing a more leveled depiction of settlement fees.

Uncollectible Expense

Q. Please explain how the Company calculated the amount of uncollectible expense included in this request.

A. As shown in my Exhibit RMP___(SRM-3) in Adjustment 4.17, the Company first calculated the test period uncollectible rate of 0.315% by dividing Utah's June 2010 unadjusted uncollectible expense (FERC 904) by Utah's June 2010 unadjusted general business revenues. This unadjusted uncollectible rate was then applied to the June 2012 normalized general business revenues, resulting in a total uncollectible expense for the 12 months ending June 30, 2012 of approximately $5.4 million. The Company's request includes an increase in uncollectible expense of approximately $646k to account for the incremental uncollectible expense the Company anticipates during the test period as a result of the additional revenue requested in this docket.

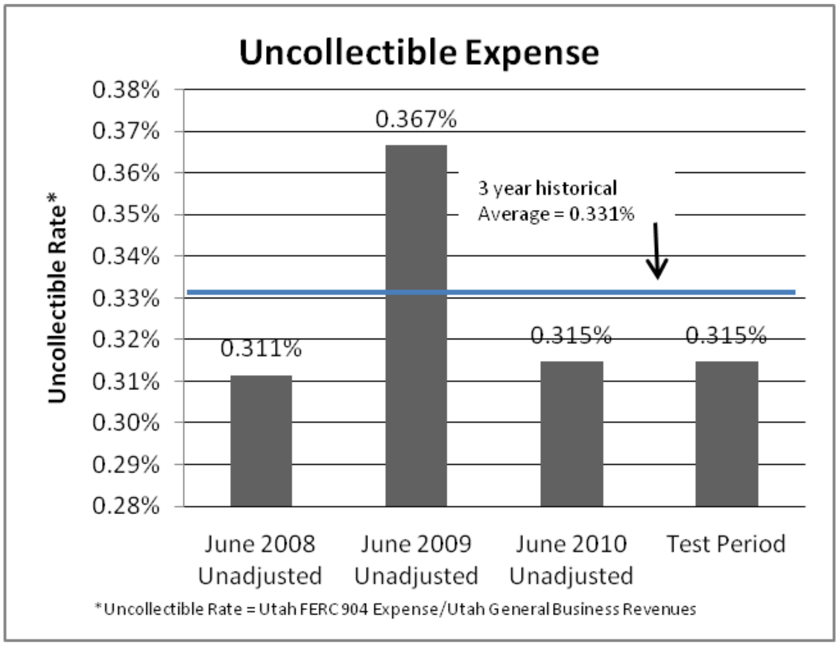
Q. How does this compare to the methodology used by the Commission in its order in Docket No. 09-035-23?

A. In the last general rate case Docket No. 09-035-23 the Commission accepted the Division's proposal to apply a 3-year historical average of the uncollectible rate to the test year general business revenues to arrive at the amount of uncollectible expense to be included in rates.

Q. Why does the Company believe that the averaging methodology used in the order in Docket No. 09-035-23 is not appropriate for this general rate case?

A. In that docket, the Commission determined that the uncollectible expense in the base period was abnormal and used a 3-year historical average as a "general approach to normalize abnormal amounts." [7] However, the order explicitly states that they would require additional evidence to establish a consistent policy for calculating test period uncollectible expense. The chart below compares the uncollectible rate in this general rate case to the prior two historical periods and the 3-year average of those periods.

[7] Docket No. 09-035-23, Commission Order, Page 86.



In this case, the base year level of uncollectible expense appears to be well within normal levels and applying a historical averaging methodology would further increase the uncollectible expense over the Company's request. The Company continues to manage its uncollectible expense levels and feels that the unadjusted uncollectible rate included in its request represents a reasonable and ongoing ratio of uncollectible expense to general business revenues. Consequently, the Company requests that the uncollectible expense be increased only to account for the additional revenue it anticipates in the 12 months ending June 30, 2012.

Pension Administration

Q. What directives did the order in Docket No. 09-035-23 include regarding pension administration costs?

A. In that order the Commission requested that future filings include analysis on pension administration costs in order to determine if those costs should be averaged over a period of several years.

Q. In preparation for this general rate case, did the Company examine the base period pension administration costs in a historical context?

A. Yes. The pension administration expense was approximately $310k in the 12 months ended June 30, 2010. By comparison, the pension administration expense was $623k and $535k in the 12 months ended June 2008 and June 2009, respectively. Applying an average would increase the pension expense by $178k or 58 percent. Therefore, the Company recommends that the test period level of pension administration expense be held constant at the base period level.

Utah Results of Operations

Q. Please describe Exhibit RMP___(SRM-3).

A. Exhibit RMP___(SRM-3), which was prepared under my direction, is Rocky Mountain Power's Utah results of operations report (the "Report"). The historical starting point for the Report is the 12 months ended June 30, 2010, which was normalized and used to calculate the revenue requirement for the Test Period, the 12 months ending June 30, 2012. 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 calculated using a thirteen month average. All other rate base items use a June 2010 historical average starting point and if applicable are forecasted out to a June 2011 and June 2012 average amount. 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-3) 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 Revised Protocol price change (plus the Rate Mitigation Premium) of $232.4 million. It details the calculation of the Rate Mitigation Premium along with the Rate Mitigation Cap and compares the results to determine the lesser of the two. Page 1.1, starting with the left-hand column 1 labeled Total Adjusted Results, displays 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 5.5 percent. The Price Change (column 2 of Tab 1, page 1.1) shows that an increase of $228.8 million in revenue is required to increase the return on equity from 5.5 percent to 10.5 percent in Utah. Column 3 reflects the Utah adjusted revenue requirement of $1.93 billion with the $228.8 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. Unadjusted results of operations are supplied side-by-side with the Test

Period results, on both a total Company and Utah-allocated basis.[8] 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 8. The calculation of these adjustments is described later in my testimony. Tab 9 is Tab 2 restated with the Utah allocation based on the Rolled-In allocation method and Tab 10 is Tab 2 restated with the Utah allocation based on the Company's proposed 2010 Protocol allocation method. Tab 11 contains the calculation of the Revised Protocol allocation factors.

Tab 3 – Revenue Adjustments

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

A. Tab 3 begins with the Revenue Adjustment Index (page 3.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenues, and the adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3), 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. **Proforma Revenue (page 3.1) –** This adjustment begins with June 2010 general business revenues and adjusts to the pro forma level for the 12 months ending June 2012 based on forecasted loads. Revenue for the Company's other jurisdictions during the Test Period is also computed. Several items are removed

[8] In conformance with filing requirement R746-700-22.B.1.

from actual booked revenue that should not be included in regulatory results, including SMUD regulatory liability amortization and out-of-period revenue. Test Period revenue reflects price changes effective January 1, 2011, from the Company's recent major plant addition filings as approved by the Commission in Docket No. 10-035-89.

Wheeling Revenue (page 3.2) – This adjustment reflects the level of wheeling revenues the Company expects in the 12 months ending June 30, 2012 by adjusting the actual revenues for normalizing, annualizing, and pro forma changes.

SO2 Emission Allowances (page 3.3) – The Environmental Protection Agency ("EPA") has established guidelines that govern the volume of sulfur dioxide ("S02") that can be emitted from power plants and granted the issuance of S02 emission allowances to cover each ton emitted. Plants that are not in compliance with EPA guidelines may purchase emission allowances from other companies that have excess allowances. Consistent with the Commission order in Docket No. 97-035-01, the Company has amortized sales of emission allowances over a four-year period. This adjustment replaces the sales from the historical period with the appropriate annual amortization, taking into account projected sales through the Test Period.

REC Revenue (page 3.4) – A market for green tags or Renewable Energy Credits ("REC") has developed where the green traits of qualifying power production facilities can be sold. These RECs may be used to meet renewable portfolio standards in various states. To comply with current or future year renewable portfolio requirements in California, Oregon, and Washington, during the Test Period the Company will not sell the portion of eligible RECs allocated to those states. This adjustment ensures Test Period REC revenue is correctly allocated among the Company's jurisdictions after considering the banking of eligible RECs. Company witness Mr. Stefan A. Bird supports the development of the total Company REC revenue forecast for the Test Period.

Joint Use Revenue (page 3.5) – This adjustment reflects the impact of the Company's proposed change to Electric Service Schedule No. 4 – Pole Attachments. The Company's proposal includes an increase in the per-pole attachment rate from $7.02 to $8.10. Company witness Mr. Jeffrey M. Kent provides the details of the Company's proposed changes to Schedule No. 4.

Ancillary Revenue (page 3.6) – An existing ancillary revenue contract will terminate December 31, 2011. This adjustment reduces ancillary revenue booked for this contract as of June 30, 2010 by 50 percent to reflect an expected level through the Test Period.

Tab 4 – O&M Adjustments

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

A. Tab 4 includes the O&M Index (page 4.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (pages 4.0.2 – 4.0.4) identifies each adjustment made to actual operations, maintenance, administrative, and general expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3), 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.

As part of this adjustment the Company is including in results the cost of subsidized sub-leases provided by the Company to the Economic Development Corporation of Utah ("EDCU") and Utah Sports Authority for office space in the One Utah Center. The Company sub-lets the office space for $1 per month rent plus operating expenses. These leases are provided by the Company as challenge grants, and the expense is situs assigned to Utah in FERC account 930. The Commission did not allow recovery of these costs in the Company's 09-035-23 general rate case due in part because the Company agreed to adjustments for vacant office space in prior cases which also removed these costs. The Company does not believe these costs should be removed because these costs are prudent and in the customers best interest and are costs that benefit our Utah customers and the state as a whole. The Company has worked with economic development organizations throughout the service territory in an effort to: 1) provide accurate and timely information to companies considering expansion or relocation to the Company's service territory; 2) help direct companies to locations where sufficient capacity exists to meet their needs at an acceptable cost; and 3) influence economic development policies that impact the overall cost of energy to existing electric customers. Making contributions to EDCU and other entities by absorbing these lease expenses is a key element to partnering with economic development organizations that, in effect, become an industrial customers first point of contact in the state. If these expenses are not allowed to be recovered in rates the Company may be forced to cancel or renegotiate these contracts.

Irrigation Load Control Program (page 4.2) – Incentive payments made to Idaho customers participating in the irrigation load control program are initially system allocated in unadjusted data. This adjustment assigns these costs directly to Idaho consistent with other demand side management programs. As discussed earlier, some Idaho parties filed testimony in the current Idaho general rate case requesting that the Idaho Irrigation Load Program be treated as a system cost, and discussions are ongoing at the MSP standing committee on this issue.

Non-Recurring Entries (page 4.3) – A few accounting entries were made to expense accounts during the 12 months ended June 2010 that are non-recurring in nature or relate to a prior period. These transactions are removed from results of operations to normalize the Test Period results. Details on the specific items in the adjustment can be found on page 4.3.1 of Exhibit RMP___(SRM-3).

MEHC Cross Charge (page 4.4) – As explained earlier in my testimony the commitment limiting the amount of charges to PacifiCorp from MEHC expires March 21, 2011. In this case the Company is including amounts actually booked in the year ended June 30, 2010, after removing an amount that should have been booked below the line.

DSM Expense and Revenue Removal (page 4.5) – This adjustment removes from regulated results revenues and expenses related to demand-side management

("DSM") programs in various states because the costs are recovered via separate surcharges and are not included in base rates. As ordered in Decision No. 09-038-T08, a $10.85 million write-off related to the SMUD liability was made through the Utah DSM account in February 2010. An offsetting amount was booked to retail revenue and is removed in Adjustment 3.1.

Generation Overhaul Expense (page 4.6) – This adjustment normalizes generation overhaul expenses using a four year average methodology. Overhaul expenses from the years ended June 2007 through June 2010 are averaged. For new generating units (Currant Creek, Lake Side, and Chehalis) where a four year history is not available, the four year average is comprised of the overhaul expense planned for the first four full years these plants are operational. The actual overhaul costs for the year ended June 2010 are subtracted from the four year average to arrive at this adjustment.

The Company's use of a four-year historical average was approved by the Commission in Docket No. 07-035-93, as was the use of a four-year average of planned expenses for the Company's new gas plants. This treatment, including escalation of the historical components of the average, was utilized in the Company's filings in Docket Nos. 08-035-38 and 09-035-23, but the Commission did not allow escalation to be applied in its final order in Docket No. 09-035-23. The Company continues to believe that the purpose of averaging is to adjust for uneven costs, not to adjust for inflation and that without escalation overhaul expenses will be systematically understated. However, consistent with the

Commission order, the Company has not applied escalation prior to averaging in this case.

MEHC Transition Savings (page 4.7) – This adjustment removes from the historical results an entry crediting expense to establish an Oregon MEHC change-in-control severance regulatory asset.

Cool Keeper Call Center Labor (page 4.8) – Starting in January 2010, contact center labor costs associated with maintaining participant agreements, removals, customer data reconciliation, and various other administrative tasks for the Cool Keeper air conditioning load control program in Utah are charged directly to the program and recovered through Utah's system benefit charge. This adjustment removes Cool Keeper related call center labor expenses incurred prior to the accounting change.

Solar Photovoltaic Program (page 4.9) – This adjustment reflects the contracted annual program costs associated with the pilot Solar Photovoltaic Utility Buy-down Program which is 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 project gathered important information on the viability of a solar program funded by participating customers, tax incentives and a utility contribution. The project also provided technical information on the integration of distributed solar resources into the Rocky Mountain Power system. This adjustment removes the O&M expenses incurred in the year ended June 2010 and includes $73,635 to reflect the balance of the program uncollected costs to be recovered after new rates become effective in 2011. A pro rata share of the annual $20,000 internal administrative expenses allowed are also assigned to this project and situs assigned to Utah.

Advertising Expense (page 4.10) – This adjustment removes general rate case advertising that was system allocated and assigns the costs directly to the jurisdiction the advertising was for. The Company agreed to this adjustment as part of the settlement reached in Docket No. 08-035-38. As of January 1, 2010, these costs are situs assigned in unadjusted results. The adjustment also removes promotional and institutional advertising costs deemed non-recoverable per Utah Rule R746-406 as well as costs for advertising ordered by the Wyoming Public Service Commission that should not be allocated to Utah.

Insurance Expense (page 4.11) – This adjustment normalizes injury and damage expenses to reflect a three year average using the cash method, consistent with the Utah Commission ruling in Docket No. 07-035-93. This adjustment also normalizes property and liability insurance expenses to reflect the elimination of the current captive insurance company replaced with self-insurance accruals as described earlier in my testimony.

O&M Expense Escalation (page 4.12) – This adjustment revises non-labor expenses for projected price changes through the Test Period. Changes are based on indices produced by IHS Global Insight, which provides a detailed assessment of the electric market both historically and into the future. The Company applies the IHS Global Insight indices to costs for materials and services only. Labor-related expenses are segregated from non-labor-related expenses and are escalated separately as described earlier in my testimony.

IHS 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 IHS Global Insight data is proprietary and subject to copyright protection. The indices utilized in the Company's filing are provided in Confidential Exhibit RMP___(SRM-4).

Utah Automated Meter Reading ("AMR") Program (page 4.13) – Two new automated meter reader programs were launched in Utah between July 2009 and June 2010 for the Tremonton, Laketown, Cedar City and Smithfield areas. The meters enable the Company to remotely obtain energy usage information and allow the Company to take advantage of a proven technology to increase effectiveness and efficiency, improve customer satisfaction and reduce safety exposures for employees. Starting in November 2009, the Company completed approximately 9,452 new meter installations in the Tremonton and Laketown districts. In addition, the Company reduced its workforce by two meter readers. Starting in March 2010, the Company began the installation of approximately 29,327 automated readers in the Cedar City and Smithfield districts. As a result, it reduced its workforce by six meter readers. This adjustment reflects the reduction in meter reading expense the Company anticipates as a result of the program through June 2012. The associated meter additions and retirements are reflected in Adjustment 8.8.

Pension Curtailment and Date Change (page 4.14) – The Commission's order in Docket No. 08-035-93 approved a stipulation permitting deferral and amortization of the pension curtailment gain resulting from employee participation in the 401(k) retirement plan option and for deferral and amortization of the increase in the pension and other postretirement welfare expense caused by the change in the annual measurement date mandated by FAS 158. Amortization of the measurement date change began on the books effective January 1, 2008. Amortization of the curtailment began on the books effective January 1, 2009. This adjustment removes the base period amortization and replaces it with the Test Period amortization.

Incremental Generation and Transmission O&M (page 4.15) – This adjustment annualizes incremental O&M from new plant in service, improvements to plants, and transmission projects that were placed into service during the 12 months ended June 2010. It also includes projected O&M for projects placed into service prior to the end of the Test Period. The adjustment also captures changes in costs at three existing facilities: first, in the second half of 2010 the cost of chemicals used at the Cholla IV scrubber will increase due to a change in the fuel source that will require increased pollution control; second, expenses are reduced because the Company plans to retire the Little Mountain plant in March 2012 after the current steam sale contract expires; and third, the Company recently amended the Lake Side plant's managed long term gas turbine parts and service contract with Siemens which will cause an increase in O&M during the Test Period.

Wage & Employee Benefits (page 4.16) – 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 the year ended June 2010. Union contract agreements and planned rates are used to escalate union labor group wages, while increases for non-union and exempt employees were based on planned increases. Incentive compensation, used by the Company to deliver market competitive pay structured in a manner that benefits customers with safe, adequate, and reliable electric service at a reasonable cost, is included at the target level for the Test Period. Pension expense and other employee benefit costs were also itemized starting with the year ended June 2010 and adjusted to the planned expense for the Test Period. This adjustment is further supported by the testimony of Company witness Mr. Erich Wilson.

Page 4.16.1 provides further description of the procedure used to compute Test Period labor costs. Page 4.16.2 of Exhibit RMP___(SRM-3) starts with a numerical summary of actual labor costs and summarizes the adjustments made to project costs to reflect the Test Period expense. This summary is followed by the detailed worksheets on pages 4.16.3 through 4.16.12 used to adjust the labor costs forward to the Test Period.

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 Index (page 5.0.1) followed by a numerical summary and the specific adjustments. 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-3), 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 Study (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.

James River Royalty Offset & Little Mountain (page 5.2) – 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 20-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 FERC Account 456, other electric revenue, for the Test Period.

This adjustment also normalizes the level of steam revenue related to the

Little Mountain plant. Contractually, steam revenue from Little Mountain is 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 revenue. This adjustment aligns the steam revenue to the gas prices modeled in GRID and reflects the termination of the sales agreement effective February 2012.

Electric Lake Settlement (page 5.3) – Canyon Fuel Company ("CFC") owns the Skyline mine located near Electric Lake, a reservoir owned by the Company which provides water storage for the Huntington generating plant. The two companies 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 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 which included reimbursement to the Company for O&M and capital costs associated with the pumping. The three year amortization of this settlement ended in December 2010. Therefore, this adjustment removes amounts included in historical results in order to properly reflect the Test Period in this case.

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 Index (page 6.0.1) followed by a numerical summary and the specific adjustments. 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-3), 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. Depreciation expense also includes the accrual for hydro decommissioning as approved in Docket No. 07-035-13. Details are provided on pages 6.1.2 through 6.1.17.

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 actual June 2010 balances. Accruals and planned spending for hydro decommissioning are also included in the adjusted depreciation reserve balance. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2010, through June 30, 2012. The 13-month average reserve balance is included in rate base. Calculations are detailed on pages 6.2.2 to 6.2.13.

Tab 7 – Tax Adjustments

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

A. Tab 7 includes the Tax Adjustment Index (page 7.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (pages 7.0.2 – 7.0.3) 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-3), 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.

Renewable Energy Tax Credit (page 7.2) – The Company is entitled to recognize certain tax credits as a result of placing qualifying renewable generating plants into service. The federal tax credit is based on the generation of the plant, 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 current renewable electricity production credit is 2.2 cents per kilowatt hour. The Utah state tax credit is based on the generation of the Blundell bottoming cycle, and the credit can be taken for four years. In addition to the Utah tax credit, the Company is able to recognize the Oregon Business Energy Tax Credit which is based on investment in specific plants and is taken over a five year period on qualifying property.

Allowance for Funds Used During Construction ("AFUDC") Equity (page 7.3) – This adjustment aligns the amount of AFUDC equity in regulatory income with the related tax Schedule M item. Consistent with the stipulation approved by the Commission in Docket No. 09-035-03, AFUDC equity is treated on a flow through basis rather than normalized for tax purposes.

Accumulated Deferred Income Tax ("ADIT") Corrections (page 7.4) – This adjustment corrects allocation factors assigned to certain accumulated deferred income tax balances.

Property Tax Expense (page 7.5) – Property tax expense for the Test Period was computed by adjusting actual property tax expense for known or anticipated changes in assessment levels through June 30, 2012. The property tax costs in this case were estimated using methods similar to those employed by the Company when estimating property tax costs in Docket Nos. 07-035-93, 08-035-38, and 09-035-23. These methods give necessary consideration to the effect that changes in the level of operating property and net operating income may have on state-by-state assessed values. Confidential Exhibit RMP___(SRM-5) provides a comprehensive description of the Company's property tax estimation procedures along with a detailed calculation of Test Period property taxes.

Non-Deductible Post-Retirement Benefits (page 7.6) – As established in Docket No. 10-035-38, this adjustment recognizes the amortization of the regulatory asset related to the Medicare tax deferral for the 12-months ending

June 2012.

Pro Forma Deferred Tax Expense (page 7.7) – Non-property-related Schedule M items in the Test Period were used to develop the deferred income tax expense. 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.

Pro Forma Deferred Tax Balance (page 7.8) – The deferred income tax expense was used to develop the deferred tax balance for the Test Period. This adjustment normalizes the accumulated deferred income tax balances to the estimated proforma level of beginning/ending average rate base balance for the Test Period. The allocation of property-related deferred income tax balances is also updated consistent with the Company's Power Tax model.

Recently, Congress has reinstated bonus depreciation for the calendar years 2010, 2011, and 2012. For qualified property placed in service on or after September 9, 2010, through December 31, 2011, 100 percent of the tax basis is deductible as bonus depreciation. For qualified property placed in 2010 through 2012, but before or after this period, 50 percent of the tax basis is deductible as bonus depreciation. The deferred tax balances in this general rate case include the tax benefits of the recently reinstated bonus depreciation.

Pro Forma Schedule M's (page 7.9) – The Schedule M items at June 31, 2010 were updated for known and measurable adjustments through June 30, 2012. Non-utility items, separate tariff items and other non-recurring items were removed from the June 30, 2010, historical period before updating. The Schedule

M items were then used to develop deferred income tax expenses and balances for June 30, 2012.

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. Federal income tax expense is calculated using the same methodology that the Company uses in preparing its filed income tax returns. Under the Revised Protocol state income tax expense is calculated using the state statutory rates applied to the jurisdictional pre-tax income. The result of accumulating those state tax expense calculations is allocated among the jurisdictions using the Income Before Tax ("IBT") factor. The detail supporting these calculations is contained on pages 2.18 through 2.20.

Under the Rolled In methodology state income tax expense is calculated the same way described above for Revised Protocol. However, under the Company's proposed 2010 Protocol allocation methodology, state income tax expense is calculated using the Company's weighted statutory state tax rate of 4.54 percent applied to each jurisdiction's pre-tax income. The Company proposed this calculation because it is consistent with the way the Company calculates tax impacts for its accounting books and it avoids swings in the IBT factor that are caused more by modeling assumptions than actual changes in underlying jurisdictional income before taxes.

Q. Docket No. 09-035-03 recently addressed deferred tax normalization as it relates to the Company's Utah results of operations. Does the revenue requirement in this case reflect the outcome of that Docket?

A. Yes. The settlement agreement reached in Docket No. 09-035-03 was incorporated into the Company's rebuttal filing in its last general rate case, Docket No. 09-035-23, and was approved in the Commission's final order. The Test Period in this case is consistent with that stipulation.

Tab 8 – Rate Base Adjustments

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

A. Tab 8 includes the Rate Base Adjustment Index (page 8.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (pages 8.0.2 – 8.0.3) 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-3), 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 using 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 the lead lag study recently prepared by the

Company using calendar year 2007 information. Based on the results of the 2007 lead lag study and subsequent revisions proposed by the DPU in Docket No. 08-035-38 the Company experiences 5.6 net lag days in Utah requiring a cash working capital balance of $19.2 million to be included in rate base.

Trapper Mine Rate Base (page 8.2) – 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 FERC 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. This treatment is consistent with Docket No. 99-035-10 and the Company’s general rate cases since that time.

Jim Bridger Mine Rate Base (page 8.3) – 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 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. This treatment is consistent with Docket No. 97-035-01 and the Company’s general rate cases since that time.

Environmental Settlement (PERCO) (page 8.4) – 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 8.5) – Customer advances for construction are booked into FERC Account 252. When they are booked, the entries do not reflect the proper allocation. This adjustment corrects the allocation of customer advances for construction in account 252.

Goose Creek Transmission (page 8.6) – 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. The assets sold included structures, 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. The Company plans to remove the Goose Creek switching station including all above ground facilities. This adjustment reduces rate base by the net book value of the switching station assets. Depreciation expense booked in the 12 months ended June 30, 2010, is removed in Adjustment 6.1.

Customer Service Deposits (page 8.7) – 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.

Pro Forma Plant Additions and Retirements (page 8.8) – To reasonably represent the cost of system infrastructure required to serve 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. The accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements as described earlier in the depreciation section.

Composite plant retirement rates were applied to pro forma plant balances included in this filing to reflect ongoing asset retirements through the Test Period. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of Test Period reserve balances in Adjustment 6.2.

Miscellaneous Rate Base (page 8.9) – This adjustment walks forward into the Test Period the balances in fuel stock and prepaid overhauls. The cost of the Company's coal plant fuel stock is increasing due to increases in the cost of coal. In order to avoid earning a double return on rate base, balances for prepaid overhauls at the Lake Side, Chehalis and Currant Creek gas plants are walked forward to reflect payments and transfers of capital to electric plant in service during the 12 months ending June 2012.

Powerdale Hydro Removal (page 8.10) – 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.

In Docket No. 07-035-14, the Company requested permission to transfer the net book value, including an offset for insurance proceeds, of the assets to an unrecovered plant regulatory asset and asked the Commission to establish an amortization period for the asset. In that Docket, the Commission approved the Company's request regarding the unrecovered plant and also allowed the Company to defer future decommissioning costs to a regulatory asset. In the order for Docket No. 07-035-93, the Commission further specified that the regulatory asset for the decommissioning costs could be amortized over three years beginning January 1, 2008. This adjustment reflects the plant balances and amortization expense in the Test Period consistent with the previous Commission orders.

Regulatory Assets (page 8.11) – This adjustment incorporates known and measurable changes to regulatory assets not addressed elsewhere in results. Amortization expense is reflected at the level expected in the test period and rate base is walked forward to its average balance over the test period. Assets impacted include Trojan unrecovered plant and decommissioning costs, Glenrock mine closure costs, and Cholla transaction costs. Balances in the electric plant acquisition adjustment and weatherization related assets are also walked forward through the Test Period.

Klamath Hydroelectric Settlement Agreement (page 8.12) – During FERC relicensing proceedings, settlement discussions occurred among PacifiCorp and other stakeholders to remove the Klamath Project. Company witness Mr. Dean S. Brockbank describes the relicensing and settlement process and the resulting settlement agreement, the Klamath Hydroelectric Settlement Agreement ("KHSA"). This adjustment adds the Klamath Project relicensing and settlement process costs into rate base and ongoing operation and maintenance expense associated with the Klamath Project is adjusted to the June 2012 level. Also, consistent with the KHSA, depreciation of all Klamath Project facilities (existing assets, relicensing and settlement process costs, and future capital additions) is set at a level that will fully depreciate the assets by December 31, 2019. Depreciation associated with the existing Klamath Project facilities is accelerated from current rates starting January 1, 2011. The Company will monitor the depreciation expense booked in the future to ensure assets reach a zero net book value by December 31, 2019.

Q. Please describe the remaining sections of the Report.

A. Tab 9 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. Tab 10 2010 Protocol recasts Tab 2 based on the Company's proposed 2010 Protocol allocation methodology. Tab 11 Allocation Factors contains the detailed derivation of the jurisdictional allocation factors applied to Test Period results using the Revised Protocol allocation methodology.

Q. Does this conclude your direct testimony?

A. Yes.