Q. Please state your name and business address with PacifiCorp dba Rocky Mountain Power ("the 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 education 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 $172.3 million requested rate increase.
- The test period utilized in this case, the 12 months ending May 31, 2013 ("Test Period").
- The 2010 Protocol and Rolled In inter-jurisdictional allocation methodologies and the agreement that was recently approved by the Utah Public Service Commission ("the Commission").
- The status of the Company's transmission rate case filed with the Federal Energy Regulatory Commission ("FERC") and its impact on wheeling revenues in this case.
- The Company's process for compiling the Test Period revenue requirement and a detailed explanation of the normalizing adjustments made to the unadjusted base period data to arrive at the Test Period.

Revenue Requirement Summary

Q. What price increase is required to achieve the requested Return on Equity ("ROE") in this case?

A. At current rate levels Rocky Mountain Power will earn an overall ROE in Utah of 6.6 percent during the Test Period. This return is less than the 10.2 percent return recommended by Dr. Samuel C. Hadaway in this case and is less than the 10.0 percent return included in the settlement stipulation approved by the Commission in Docket No. 10-035-124 ("2011 GRC"). An overall price increase of $172.3 million is required to produce a 10.2 percent ROE under the approved 2010 Protocol allocation method. As I will explain later in my testimony, the same price increase is required when Utah revenue requirement is determined using the Rolled In allocation method. Exhibit RMP___(SRM-1) provides a summary of the Company's Utah-allocated results of operations for the Test Period. Exhibit RMP___(SRM-2) provides a summary index identifying each normalizing adjustment and where each adjustment is addressed in the Company's filing.[1] Details supporting the revenue requirement by FERC account and the allocation of the various revenue requirement components to Utah are provided in Exhibit RMP___(SRM-3).

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 June 1, 2012, and ending May 31, 2013. The Test Period utilizes a 13-month

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

average rate base with a historical base period of the 12 months ended June 30, 2011.

Q. Why did the Company use the year ending May 31, 2013, as the Test Period?

A. Paragraph 69 of the stipulation in the 2011 GRC states:

> The Parties agree that in the Company's next general rate case application in Utah, the Company will use, and the Parties will not oppose use of, a forecast test period ending no later than fifteen months beyond the end of the month in which the rate case application is filed with a thirteen-month average rate base.

On December 15, 2011, the Company filed with the Commission a notice of intent to file a general rate case and proposed a test period ending May 31, 2013, consistent with the stipulation. On January 19, 2012, the Commission issued an order approving the Company's test period. The order states:

> In light of the test year stipulation quoted above and the absence of opposition to the Company's proposed test year, we find the proposed test year meets the statutory requirements. See Utah Code Ann. § 54-4-4(3). It is approved. Accordingly, consistent with Utah Administrative Code R746-700-10(B), the Company need not provide the alternative test period demonstration required by Subsection (A)(2) of that rule.

My testimony and exhibits provide the detailed explanation of all adjustments required to be made to the base period data (the year ended June 2011) to arrive at the Test Period.

Q. Does the base period match the unadjusted results of operations previously filed with the Commission?

A. Yes. The accounting data relied on for the base period in this case is the same data used for the unadjusted results of operations for the 12 months ended June 30, 2011 filed with the Commission in October 2011. However, the jurisdictional allocation model ("JAM") used for the rate case synchronizes interest and cash working capital for the unadjusted inputs while the JAM used for the results of operations does not. This synchronization of the unadjusted data produces an apparent difference between the two models for interest expense, current income taxes, and the cash working capital allowance.

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

A. The Company is requesting that new rates become effective October 12, 2012, 240 days after the Company's rate case filing.

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, increases in the Company's operation and maintenance expenses, increases in net power costs, decreases in retail revenues, and decreases in REC revenues. Company witnesses Mr. Douglas N. Bennion and Mr. Darrell T. Gerrard provide support for investments in new facilities required to serve customers, Mr. Dana M. Ralston and Mr. Mark R. Tallman provide testimony on the costs to operate various generating facilities, Mr. Gregory N. Duvall provides testimony on net power costs, and Mr. Stefan A. Bird provides testimony on the decrease in REC revenues

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, 2011. 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

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 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 4.11) which reflects efficiencies from automated meter reading projects, and the Incremental O&M adjustment (Adjustment 4.9) which includes the cost of operating and maintaining our generating plants.

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 2010 Protocol allocation method as described in the Agreement Pertaining to PacifiCorp's September 15, 2010 Application for Approval of Amendments to Revised Protocol Allocation Methodology ("2010 Protocol Agreement") filed with the Commission on June 27, 2011, under Docket No. 02-035-04 and approved by the Commission at a hearing held November 8, 2011. Consistent with the 2010 Protocol Agreement, allocation of results under the 2010 Protocol is based on the Rolled In allocation methodology, and the Hydro Endowment and Klamath adjustments called for in the 2010 Protocol have been zeroed out. Consequently, Utah-allocated results of operation are identical under either the 2010 Protocol or the Rolled In allocation methods. For comparison purposes the Test Period results for this case in Exhibit RMP___(SRM-3) are provided using both the 2010 Protocol (Tab 2) and Rolled-In (Tab 9) methods. In addition, I have provided the calculation of the 2010 Protocol results including the Hydro Endowment and Klamath adjustments using Test Period information (Tab 10) as required by the 2010 Protocol Agreement.

Q. Were any inter-jurisdictional allocation issues left unresolved in the 2010 Protocol?

A. Yes. An on-going inter-jurisdictional allocation issue is the treatment of the Company's Class 1 DSM programs – the Idaho Irrigation Load Control program, the Utah Irrigation Load Control program, and the Utah Cool Keeper program. According to the 2010 Protocol, Class 1 DSM programs are to be treated as situs resources; program costs are assigned directly to the host state and program benefits in the form of reduced jurisdictional load are reflected in the host state's contribution to the monthly system coincident peaks. The Idaho Public Utilities Commission recently ordered that the Idaho Irrigation Load Control program would be system-allocated for purposes of setting rates in Idaho, and parties to the 2010 Protocol have been working to determine a path forward for the other states. Paragraph 12 of the 2010 Protocol Agreement states:

> The Parties acknowledge that the emerging issues related to the inter-state allocation of Class 1 demand-side management (DSM) programs are not addressed in this agreement and should not be considered in this phase of the proceeding. Additional analysis and discussion of these issues may be undertaken in the Standing Committee workgroups and the Parties understand that the Company may make a subsequent Application to modify the allocation of some or all Class 1 DSM resources.

Q. How are Class 1 DSM programs treated in this case?

A. Because no consensus has been reached among participants in the MSP Standing Committee workgroup regarding how to move this issue forward, the Company has continued to treat Class 1 DSM programs as situs resources in this filing. This is the same treatment utilized in the 2011 GRC. As of the date of filing this general rate case, the MSP Standing Committee workgroup continues its work on this issue, and the Company may need to reflect the outcome of that process in this case if agreement is reached that differs from current treatment.

Transmission Rate Case

Q. What is the status of the Company's transmission rate case filed with FERC?

A. The Company's transmission rate case was filed with FERC on May 26, 2011, under Docket No. ER11-3643. The Company's FERC rate case proposes updated wholesale rates for transmission and other ancillary services provided under the Company's Open Access Transmission Tariff ("OATT"). FERC issued an order August 8, 2011, accepting the filing, suspending it for a five-month period, subject to refund, and establishing hearing and settlement procedures.

Q. Is incremental revenue from the Company's transmission rate case reflected in the revenue credits proposed for the Test Period in this case?

A. No. Although FERC allows the Company's proposed rate changes to be made effective prior to issuance of a final order, any revenue from the new rates is subject to refund pending the conclusion of the FERC proceeding. The Company commenced billing at the new rates and charges for service in January 2012, but due to the often lengthy settlement process at FERC to resolve rate cases, the Company is not able to speculate on the date FERC will issue an order approving the final OATT rate changes. As a result, the Company has not projected any incremental impact on the Test Period related to the transmission rate case.

Q. If the impacts of the transmission rate case are not included in this filing, how does the Company propose to ensure Utah customers receive credit for any additional revenue resulting from that case?

A. Since the Company does not know the outcome of the FERC proceeding, including what the final rates will be, the Company proposes to continue the deferral treatment established in the settlement stipulation resolving the 2011 GRC. That is, beginning with the effective date of new FERC transmission rates, additional revenue related to the FERC proceeding shall be deferred and credited to customers through the energy balancing account ("EBA") without application of the 30 percent sharing mechanism. Such treatment will continue until a new base for wheeling revenue is established in a general rate case that includes the impact of the current FERC proceeding.

As I discussed in my rebuttal and surrebuttal testimony in the 2011 GRC, the overall increase in revenue from the transmission rate case is not anticipated to be significant. The customer impact statement accompanying the Company's transmission rate case filing shows OATT revenues using the proposed rates applied to historic loads. According to that impact statement the Company expects approximately $1.3 million in incremental annual third-party transmission revenues and $1.7 million in incremental annual ancillary service revenues under the proposed rates, exclusive of any short-term or non-firm revenues. Assuming the full requested increase is granted, this increase in revenue credits would amount to approximately $1.3 million on a Utah-allocated basis.

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, 2011, which was normalized and then projected forward to calculate the revenue requirement for the Test Period, the 12 months ending May 31, 2013. The Report provides totals for revenue, expenses, depreciation, net power costs, taxes, rate base, and loads in the Test Period. Specific rate base items that have been walked out through the Test Period are included using a thirteen month average. Rate base items with no related normalizing adjustment remain stated at the average balance of June 2010 and June 2011. 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 2010 Protocol allocation methodology. Page 1.0 is the calculation of the 2010 Protocol price change of $172.3 million based on the Utah results of operations for the Test Period. The Total Adjusted Results column is carried forward from the results of operations summary, page 2.2, and shows a ROE for Utah of 6.6 percent. The Price Change (column 2 of Tab 1, page 1.1) shows that an increase of $172.3 million in revenue is required to increase the return on equity from 6.6 percent to 10.2 percent in Utah. Column 3 reflects the Utah adjusted revenue requirement of $1.95 billion with the $172.3

million price increase included. Page 1.1 of Tab 1 supports the calculation of additional revenue-related uncollectible expense and franchise taxes associated with the price change. Page 1.2 details the calculation of the net operating income percentage. Page 1.3 shows the same details as page 1.0 but under the Rolled-In rather than the 2010 Protocol allocation method. It is provided to show that results are identical under either method, consistent with the 2010 Protocol Agreement. Pages 1.4 through 1.5 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 2010 Protocol. 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.[2] 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. Tab 10 is Tab 2 restated with the Utah allocation based on the 2010 Protocol allocation method including a dynamic Embedded Cost Differential adjustment ("ECD"). Tab 11 contains the calculation of the 2010 Protocol allocation factors and the Hydro Endowment component of the ECD.

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

Tab 3 – Revenue Adjustments

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

A. Tab 3 begins with the Revenue Adjustment Index, which is a list of adjustments used to project retail revenue. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenue 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 summary 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. **Pro Forma Revenue (page 3.1) –** This adjustment begins with June 30, 2011, general business revenues and adjusts to the pro forma level for the 12 months ending May 31, 2013 based on forecasted loads. Revenue for the Company's other jurisdictions during the Test Period is also computed using current rates in the respective states. Several items are removed from actual booked revenue that should not be included in Test Period results including special contract pass-through revenue, Schedule 40 revenue from previous major plant addition filings, and out-of-period revenue. Test Period revenue reflects the recent changes to base rates approved in the 2011 GRC effective September 21, 2011.

Wheeling Revenue (page 3.2) – This adjustment reflects the level of wheeling revenue for the 12 months ending May 31, 2013, by adjusting the actual revenue for normalizing, annualizing, and pro forma changes. As discussed earlier in my testimony, the final outcome of the Company's transmission rate case is not yet known and the potential impact on the Test Period in this rate case is not included in the adjustment.

SO2 Emission Allowances (page 3.3) – The Environmental Protection Agency ("EPA") has established guidelines that govern the volume of sulfur dioxide ("SO2") that can be emitted from power plants and granted the issuance of SO2 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 ("RECs") 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. Bird supports the development of the total Company REC revenue forecast for the Test Period.

Ancillary Revenue (page 3.5) – In December 2011 the Company renewed its contract with Seattle City Light ("SCL") to receive real time output from SCL's share of the Stateline wind farm and return power two months later. The ancillary revenue booked in the 12 months ended June 2011 is adjusted to reflect the Test Period revenue expected per the terms of the new contract. The impact on NPC is included in adjustment 5.1.

Joint Use Revenue (page 3.6) – This adjustment reflects a change to Joint Use Revenue – Schedule 4 resulting from a proposed decrease in the per pole attachment rate from $7.02 to $6.33. The amount proposed by the Company is calculated in accordance with Commission Rule R746-345-5. Company witness Mr. Jeffery M. Kent provides additional supporting detail.

Tab 4 – Operation and Maintenance (O&M) Adjustments

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

A. Tab 4 includes the Operations and Maintenance Expense Adjustment Index followed by a numerical summary and the specific adjustments. The numerical summary (pages 4.0.2 – 4.0.3) 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 summary showing the affected FERC account(s), allocation factor, dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments made to operation and maintenance 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. It also reallocates certain gains and losses on property sales and regulatory expenses in the base period to reflect the appropriate allocation.

Wage & Employee Benefits (page 4.2) – Labor-related costs for the Test Period are computed by adjusting salaries, incentives, health benefits, and costs associated with pension, post retirement benefits, and post employment benefits for changes expected beyond the actual costs experienced in the period ended June 2011. Company witness Mr. Erich D. Wilson's testimony provides an overview of the compensation and benefit plans provided to employees at the Company and supports the costs related to these areas included in the Test Period.

Collective bargaining agreements are used to escalate union wages where increases are specified, and wage increases for non-union and exempt employees are based on the Company's targets. Incentive compensation for non-union employees is included using a three-year historical average, calculated by multiplying the pro forma wages in this case by the three-year historical average of the actual payment rate. Pension expense and other employee benefit costs are adjusted to the planned expense for the Test Period, based on actuarial reports where available or by escalating actual costs.

In Docket No. 09-035-23 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. In the 2011 GRC the Company provided analysis showing that averaging the pension administrative expense would increase the level included in the test period in that case. A similar analysis of pension administration costs in this case would produce the same results – if a historical average is used the Test Period expense would be higher.[3] Therefore, the Company recommends that the test period level of pension administration expense be held constant at the base period level.

Page 4.2.1 of Exhibit RMP___(SRM-3) provides further description of the procedure used to compute Test Period labor costs. Page 4.2.2 contains a numerical summary of actual labor costs in the year ended June 2011 and summarizes the adjustments made to project costs through the Test Period. This summary is followed by detailed worksheets on pages 4.2.3 through 4.2.11.

Idaho Irrigation Load Control Program (page 4.3) – Incentive payments made to Idaho customers participating in the irrigation load control program and a portion of the program's administrative costs are initially system allocated in unadjusted accounting data. Consistent with the 2010 Protocol, Test Period DSM costs are situs assigned to the states in which the costs are incurred to match the benefit of reduced load reflected in the inter-jurisdictional allocation factors. This adjustment corrects the booked allocation to assign these costs directly to Idaho. As previously discussed, allocation of Class 1 DSM programs continues to be reviewed by the MSP standing committee workgroup. In the event the MSP standing committee reaches agreement on proposed changes to the treatment of some or all of the Company's Class 1 DSM programs for purposes of allocations, the Company may need to revise the treatment of Class 1 DSM programs in this case.

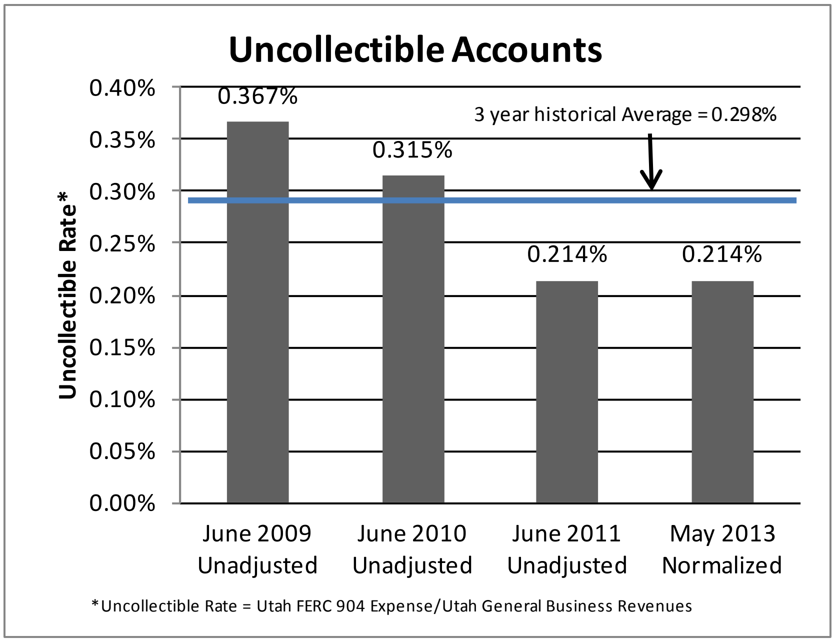
[3] The pension administration expense was approximately $111k in the 12 months ended June 30, 2011. By comparison, the pension administration expense was $535k and $310k in the 12 months ended June 2009 and June 2010, respectively. Applying an average would increase the pension expense by $207k or 186%.

Remove Non Recurring Entries (page 4.4) – A few accounting entries were made to expense accounts during the 12 months ended June 2011 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. Details on the specific items in the adjustment can be found on page 4.4.1.

Uncollectible Accounts (page 4.5) – Uncollectible accounts expense is adjusted to the Test Period level by applying the historical uncollectible rate (Utah uncollectible accounts expense in FERC Account 904 divided by Utah general business revenues) to the normalized general business revenue in the Test Period. This treatment is the same methodology used in the Company's 2011 GRC filing.

In Docket No. 09-035-23 the Commission accepted the Division's proposal to apply a three-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. In that docket, the Commission determined that the uncollectible expense in the base period was abnormal and used a three-year historical average as a "general approach to normalize abnormal amounts."[4] However, the order stated that additional evidence would be required 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 three-year average of those periods.

[4] Docket No. 09-035-23, Report and Order dated February 18, 2010, Page 86.



Because the uncollectible rate is trending down, applying a historical average would increase the uncollectible expense. The same held true in the 2011 GRC. The Company continues to manage its uncollectible expense levels and feels that the unadjusted uncollectible rate included in its request represents a reasonable ratio of uncollectible expense to general business revenues for use in this rate case.

DSM Revenue and Expense (page 4.6) – This adjustment removes from regulated results revenues and expenses related to DSM programs in various states because the costs are recovered via separate surcharges and are not included in base rates. In Utah these costs are recovered through the Demand Side Management Cost Adjustment, Schedule 193.

Insurance Expense (page 4.7) – This adjustment normalizes insurance expense related to third-party liability for injuries and damages as well as damage to Company property. This adjustment also reflects the end of coverage by the

MidAmerican Energy Holdings Company captive insurance on March 21, 2011. Injuries and damages expense is set at the three-year historical average using the cash method, consistent with the Utah Commission ruling in Docket No. 07-035-93. Insurance expense for damage to Company property will now be an accrual to a reserve account, with the accrual set at the three-year historical average of actual losses. This treatment for insurance expense, including the expiration of the captive insurance coverage, was included in the 2011 GRC.

With the expiration of coverage by the captive insurance company, per event deductibles for property damage were raised from $25,000 to $250,000 for distribution property and to $1,000,000 for transmission and non-T&D property. Consequently, costs previously covered by insurance are now charged to operation and maintenance expense. The Company's adjustment accounts for this change in coverage by transferring costs from insurance expense to operations and maintenance expense.

This adjustment also removes accounting entries booked in the base period related to the California Catastrophic Event Memorandum Account regulatory asset, entries that should not be included in Utah-allocated results.

In the final item, insurance proceeds related to settlement of previous litigation surrounding the Colstrip plant are removed. In its order resolving the Company's 2009 general rate case, Docket No. 09-035-23, the Commission reduced the expense related to the Colstrip settlement that was allowed in the test period from $1.2 million to $400,000. The Commission's order was based on the Company's surrebuttal adjustment reducing the test period expense, but amortizing the Colstrip settlement over three years. However, the Commission did not accept the Company's amortization proposal, and effectively left the recovery of Colstrip settlement costs at 1/3 of the amount booked at the time, or $800,000 less that originally requested. Since that case, the Company has received insurance proceeds partially offsetting the cost of the Colstrip settlement. In December 2010 the Company booked a credit of $568,605 for the receipt of these proceeds. Because recovery of the original Colstrip settlement expense was reduced by $800,000, the Company has removed the credit of $568,605 from the base period in this case.

Generation Overhaul Expense (page 4.8) – This adjustment normalizes generation overhaul expenses using a four-year historical average for the years ended June 2008 through 2011. For newer generating units (Lake Side and Chehalis), the four-year average is comprised of the overhaul expense planned for the first four full years these plants are operational. Prior to averaging, annual expenses are restated to June 2011 dollars. A four-year average is consistent with the normalized outages assumed in the GRID model to compute Test Period net power costs.

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.

In the 2011 GRC the Division of Public Utilities supported the concept of restating annual expenses to constant dollars prior to averaging, and the Company adopted that position in its rebuttal filing. Dr. Artie Powell correctly pointed out that from an economic standpoint, averaging dollars from multiple years requires the dollars to be stated on a consistent basis prior to averaging. The Company agrees with his statement that: "economic theory suggests that in order to compare two values separated by time, the values need to have a common monetary base: the values should be expressed in real terms."[5]

The purpose of averaging is to adjust for uneven costs, not to adjust for inflation. A simple example below shows the impact of averaging, assuming a 2.5 percent inflation rate, a $100 amount in year one, and a four year average of years one through four used to project costs in year five. Using this assumption, Example 1 shows the impact without adjusting for inflation, and Example 2 shows the impact when years one through four are stated in real or constant dollars.

As shown in the first example, with no escalation to account for inflation a four year average of costs is $103.8, much less than the projected costs in year five, resulting in an expense level that is 2.5 years old compared to the current expenses. In Example 2, the average is equal to the year five amount resulting in an accurate forecast.

[5] Direct testimony of Dr. Artie Powell, Docket No. 10-035-124, page 28, lines 475 – 477.

Example 1

Year		Amount	
1	$	100.0	
2		102.5	Avg.
3		105.1	$103.8
4		107.7	
5		110.4	

Example 2

Year		Amount	Escalation		Adjusted Amount	
1	$	100.0	1.104	$	110.4	
2		102.5	1.077		110.4	Avg.
3		105.1	1.051		110.4	$110.4
4		107.7	1.025		110.4	
5		110.4				

Incremental O&M (page 4.9) – This adjustment accounts for changes in costs at the Company's thermal, hydro, and wind generation plants due to changes in operations and regulatory requirements. Support for this adjustment is provided in the testimony of Company witnesses Mr. Ralston and Mr. Tallman.

Solar Photovoltaic Program (page 4.10) – 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 was recently extended one year by the Commission in Docket No. 11-035-104. This adjustment reflects program O&M at the annual funding level of $385,000, including $365,000 external program costs and $20,000 of internal administration expenses, situs assigned to Utah.

Utah Automated Meter Reading Program (page 4.11) – In August 2011 the Company began installing approximately 33,396 automated meters in its Utah service territory still lacking such equipment, including Vernal, Richfield, Price, Dixie, Cedar, Blanding, and Moab. 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. The new installations are expected to allow the Company to reduce its workforce by an additional eight meter reading positions. This adjustment reflects the reduction in meter reading expense the Company anticipates as a result of the program through May 2013. The associated meter additions and retirements are reflected in Adjustment 8.6.

O&M Expense Escalation (page 4.12) – This adjustment increases non-labor expenses for projected inflation through the Test Period. Projected increases or decreases in costs are based on IHS Global Insight indices, which provide a detailed assessment of the electric market both historically and into the future. The indices used are based on electric utility costs for materials and services only, which exclude labor expense, according to the Uniform System of Accounts defined by FERC for major electric utilities.

The IHS Global Insight 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 study used to prepare this filing was the third quarter 2011 forecast, released November 10, 2011. The IHS Global Insight data is proprietary and subject to copyright protection, therefore the indices utilized in the Company's case are provided in Confidential Exhibit RMP___(SRM-4).

Tab 5 – Net Power Cost Adjustments

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

A. The Net Power Cost Adjustment Index on page 5.0.1 is an index of adjustments made to NPC-related items. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on overall revenue requirement. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3), which contains a summary 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 NPC study presents normalized Test Period steam and hydro power generation, fuel, purchased power, wheeling expense and sales for resale based on the Company's GRID model. It also normalizes hydro generation, weather conditions and plant availability as described in the testimony of Company witness Mr. Duvall.

James River Royalty Offset (page 5.2) – On January 13, 1993, the Company executed a contract with James River Paper Company ("James River") 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 NPC 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.

Little Mountain (page 5.3) – The Company has provided both electricity and steam from its Little Mountain plant to the Great Salt Lake Minerals Company ("GSLM") since 1968. The previous contract associated with this arrangement was due to expire February 28, 2012. However, on August 1, 2011, the electrical generator at the Little Mountain plant experienced a significant electrical fault and is no longer producing energy. In August 2011, the Company installed a mobile packaged boiler in order to provide enough steam for GSLM to maintain its operations. Since the plant no longer produces energy due to the generator failure, a portion of the plant was retired in December 2011. The remaining portion of the plant and two rental boilers will be used to deliver steam to GSLM under a new contract executed on December 13, 2011. Under this new contract, the Company will continue to provide steam to GSLM through July 31, 2012. In return, GSLM will pay the Company a fee to cover the costs for the boiler rental, labor and O&M expense, plus an administrative fee. This adjustment removes the base period steam revenue and O&M expense and adds the revenue related to the administrative fee under the terms of the new contract. The asset balance is removed in the Pro Forma Plant Additions and Retirements Adjustment (page 8.6); depreciation expense is removed in the Depreciation and Amortization Expense Adjustment (page 6.1) and the accumulated depreciation reserve is removed in the Depreciation and Amortization Reserve Adjustment (page 6.2).

Electric Lake Settlement (page 5.4) – Canyon Fuel Company ("CFC") owns the Skyline mine located near Electric Lake, a reservoir owned by the Company to provide water storage for the Huntington generating plant in Utah. The two companies disputed the claim made by the Company 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 two companies negotiated a settlement of the claims, including reimbursement to the Company for operations and maintenance and capital costs associated with pumping water back into the lake, and the benefits were deferred and amortized over three years. This adjustment removes the amortization from results because the amortization ended in January 2011. The benefit of the settlement has been reflected in the Company's Utah general rate cases since the 2008 rate case, Docket No. 08-035-38.

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 Adjustment Index followed by a numerical summary and the specific adjustments. The summary on page 6.0.1 is an index of adjustments to depreciation and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3), which contains a summary 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 6.

A. **Depreciation and Amortization Expense (page 6.1) –** The depreciation and amortization expense for the Test Period is calculated by applying functional composite depreciation and amortization rates to projected plant balances by month. Depreciation related to pro forma capital additions is computed from the date the depreciable asset is placed into service. 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.

Depreciation and Amortization Reserve (page 6.2) – Accumulated depreciation and amortization balances for the Test Period are calculated by walking the June 2011 actual balances forward using the pro forma depreciation and amortization expense and plant retirements as calculated in the Depreciation and Amortization Expense Adjustment (page 6.1) and the Pro Forma Plant Additions and Retirements Adjustment (page 8.6). 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 through May 31, 2013, detailed on pages 6.2.2 to 6.2.13. Consistent with electric plant in service, the 13-month average accumulated depreciation and amortization reserve balance is included in rate base.

Tab 7 – Tax Adjustments

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

A. Tab 7 includes the Tax Adjustment Index followed by a numerical summary and the specific adjustments. The summary begins on page 7.0.1 with an index of adjustments, and the numerical summary on pages 7.0.2 through 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 summary 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.

Property Tax Expense (page 7.2) – 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 each Utah general rate case since Docket No. 07-035-93. 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.

Renewable Energy Tax Credit (page 7.3) – The Company is entitled to recognize certain tax credits as a result of placing qualifying renewable energy generation 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 Code § 45(b)(2), the current renewable electricity production credit is 2.2 cents per kilowatt hour. In addition, the Company is able to recognize the Oregon Business Energy Tax Credit, which is based on investment and is taken over a five-year period on qualifying property. A Utah state tax credit is currently available based on the generation of the Blundell bottoming cycle, but that credit expires in December 2011.

AFUDC Equity (page 7.4) – 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.

Medicare Tax Deferral (page 7.5) – 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 Test Period.

Pro Forma Schedule M Items (page 7.6) – This adjustment incorporates changes to Schedule M items into the results of operations. The Schedule M items at June 30, 2011, were walked forward through the Test Period. Non-utility items, separate tariff items and other non-recurring items are removed from results. The

Schedule M items were then used to develop deferred income tax expenses and balances for the Test Period.

Pro Forma Deferred Income Taxes (page 7.7 & page 7.8) – The non-property-related Schedule M items were directly used to develop the corresponding deferred income tax expense. The property-related deferred income tax expense was generated using the capital additions and resulting book and tax depreciation. The deferred income tax expense was then used to develop the deferred tax balance for the Test Period.

Wyoming Wind Generation Tax (page 7.9) – In its 2010 budget session, the Wyoming Legislature enacted W.S. 39-22-101 through 39-22-111, which imposes a tax on electricity produced from wind resources located within the state of Wyoming. Starting in January 2012, a $1 per megawatt hour generation tax will be due on all electricity the Company generates from its Wyoming wind resources, effective three years after the turbine first produces electricity. This adjustment normalizes the tax into the Test Period based on eligible wind generation in the NPC study.

Repairs Deduction Deferred Accounting (page 7.10) – As a result of a stipulation in Docket Nos. 09-035-03 and 09-035-23 regarding income tax treatment, a regulatory liability equal to the revenue requirement impact of the difference in the deduction for repairs recognized in regulatory results versus recognized for tax return purposes for calendar years 2009 and 2010 will be included in rate base and amortized over a period of not more than five years. This adjustment expenses the entire amount over just one year given its magnitude and direction. The amortization reduces Test Period expenses, and therefore the revenue requirement, by approximately $60,000.

ADIT Corrections (page 7.11) – This adjustment corrects allocation factors assigned to certain accumulated deferred income tax balances.

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 followed by a numerical summary and the specific adjustments. The summary begins on page 8.0.1 with an index of adjustments made to electric plant in service and other rate base components. 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 summary showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

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

A. **Cash Working Capital (page 8.1) –** This adjustment supports the calculation of cash working capital included in rate base based on the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on the lead lag study prepared by the Company using calendar year 2010 information.[6] A complete copy of the 2010 study is provided in this case as part of the Company's response to filing requirement R746-700-22.D.43. Based on the results of the lead lag study the Company experiences 4.92 net lag days in Utah and requires a cash working capital balance of $18.7 million 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 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 operation and maintenance 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.

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. Due to the ownership arrangement, the mine investment is not included in the Company's unadjusted results of operations, and the normalized coal costs for Bridger include all operating and maintenance costs but do not include a return on investment. This adjustment adds the Company's portion of the Bridger Mine net plant investment to rate base in order for the Company to earn a return on its investment.

[6] At the time of filing the Company had completed the 2010 lead lag study for Utah, but not for the remaining states. Net lag days in the jurisdictional allocation model are from the 2010 study for Utah and the 2007 study for the remaining states. Other states' net lag days do not impact the calculation of Utah-allocated revenue requirement.

Environmental Settlement (PERCO) (page 8.4) – In 1996, the Company received an insurance settlement of approximately $38 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. The Company expects these proceeds to be exhausted prior to May 31, 2013.

Customer Advances for Construction (page 8.5) – Refundable customer advances for construction are booked to FERC Account 252. The June 2011 balances do not reflect the proper allocation because amounts were recorded to a corporate cost center location rather than state-specific locations in the Company's accounting system. This adjustment corrects the allocation of customer advances.

Pro Forma Plant Additions and Retirements (page 8.6) – To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be completed by the end of the Test Period. Company business units identified capital expenditures that will be placed into service 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. Plant additions are included on a 13-month average basis for the Test Period. Descriptions of large individual projects are included on pages 8.6.31 through 8.6.39.

Composite plant retirement rates were applied to pro forma plant balances to reflect ongoing asset retirements through the Test Period. This adjustment incorporates 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 the Depreciation and Amortization Reserve Adjustment (page 6.2).

Miscellaneous Rate Base (page 8.7) – This adjustment reflects the Test Period fuel stock balance into results based on projected inventory by plant, along with offsetting working capital deposits. In addition, prepaid overhaul balances in FERC Account 186 for the Lake Side, Chehalis, and Currant Creek gas plants are walked forward to reflect the continued payments and the transfer of these costs into plant in service through the end of the Test Period. Also, the balance in plant held for future use related to the acquisition of the Cottonwood coal lease is walked forward through the Test Period, including approximately $3.3 million for development costs. The Cottonwood coal lease was included in the 2011 GRC.

Powerdale Hydro Removal (page 8.8) – Powerdale was decommissioned after it was damaged by a flood in November 2006. Deferred accounting for the unrecovered plant balance and decommissioning costs was authorized by the Commission in Docket No. 07-035-93. The regulatory assets for unrecovered plant and decommissioning costs were both fully amortized by December 2010. This adjustment removes costs related to the Powerdale hydroelectric plant from results. In addition, in the 2011 GRC the Company agreed to true-up the decommissioning estimate authorized in Docket No. 07-035-93 with the reduced costs included in the 2011 GRC. This adjustment amortizes the difference between the estimates used in the two previous cases over a period of two years.

Regulatory Asset Amortization (page 8.9) – 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 asset balances are walked forward to the average balance over the Test Period. Assets impacted include Trojan unrecovered plant and decommissioning costs, Glenrock mine closure costs, Cholla transaction costs, pension curtailment gain and measurement date change, electric plant acquisition adjustment, and weatherization assets. The cost of utilizing an independent evaluator to review RFPs in Utah, net of bid fees received, is also included as a deferred asset and is amortized over the Test Period. Oregon independent evaluator fees that are recovered by Oregon customers but were allocated system-wide in the base period are removed from Utah results.

Customer Service Deposits (page 8.10) – 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.

Klamath Hydroelectric Settlement Agreement (page 8.11) – This adjustment accounts for the Test Period costs related to the Klamath Hydroelectric Settlement Agreement ("KHSA"). The KHSA impacts the Test Period in three main areas: depreciation and amortization expense associated with the Klamath-related assets, inclusion of the Klamath relicense and process costs in rate base, and allocation of the KHSA dam removal surcharge.

A similar adjustment was included in the 2011 GRC but the settlement approved by the Commission in that case deferred the issue to the current rate case. Paragraph 46 of the 2011 GRC settlement states:

> The "Klamath Postponement" adjustment … is based on Parties' agreement, for purposes of the General Rate Case only, that (a) existing plant assets associated with the Klamath Hydroelectric Project will continue to be depreciated using previously-approved depreciation schedules, (b) issues relating to the Klamath Hydroelectric Settlement Agreement raised by the Company and intervening parties in the General Rate Case shall be postponed to a future proceeding, and (c) relicensing and settlement process costs shall continue to be deferred and accrue a carrying charge based on the AFUDC rate and shall not be amortized or included in rate base unless ordered by the Commission in a future proceeding.

In this case, the Company has again incorporated the impact of the KHSA into the Test Period and requests the Commission approve its inclusion in rates, including the impact of postponing the acceleration of depreciation expense and the accrual of additional AFUDC on the balance of relicensing and settlement process costs. Company witness Ms. Andrea L. Kelly provides testimony describing the KHSA, supporting the allocation of the surcharge, and explaining why the KHSA is in the best interest of customers**.** Page 8.11.5 demonstrates that the balance of relicensing and settlement process costs, on a total Company basis, will grow from $74.1 million at December 31, 2010, to approximately $81.8 million by May 2012 due to the accrual of additional AFUDC until the asset is placed into service.

Accelerated depreciation of existing facilities and amortization of the process costs begins in the Test Period at rates that will fully depreciate the assets by the end of calendar year 2019. Depreciation rates of existing Klamath facilities will require minor adjustments over time to account for the impact of additional capital placed into service, asset(s) retired and any related net salvage. This is accomplished in the Company's accounting system by placing a terminal date of December 31, 2019, on each asset, which will then be proportionately depreciated over the remaining period.

The testimony of Company witness Mr. Tallman provides detail regarding the Klamath O&M required for the Test Period. The KHSA dam removal surcharge is also included in the Test Period and is allocated to all states consistent with a Rolled In allocation of costs for all system resources.

Miscellaneous Asset Sales and Removals (page 8.12) – This adjusts the Company's filing for sales or removals of various assets, including the sale of transmission assets to Black Hills Power ("BHP"), the sale of Snake Creek hydroelectric plant to Heber Light & Power Company, the removal of Deseret Power's portion of the Hunter Unit 2 scrubber and turbine upgrade, the decommissioning of the Condit hydroelectric plant, and the removal of the Goose Creek switching station. A brief description of each item is provided below.

<u>BHP Transmission Asset Sale</u> – On December 29, 2010, the Company sold ownership interests in certain transmission assets to BHP. This adjustment removes the O&M expense related to the assets, and the depreciation expense is removed in the Depreciation and Amortization Expense Adjustment (page 6.1). A corresponding adjustment was included in the 2011 GRC.

<u>Snake Creek Hydroelectric Asset Sale</u> – On September 26, 2011, the Company sold an undivided ownership interest in the Snake Creek hydroelectric

generation plant facilities located in Wasatch County, Utah, to Heber Light & Power Company. This adjustment removes the O&M expense from the base period. The impacts of the sale on electric plant in service, depreciation reserve and depreciation expense are reflected in the adjustments to Pro Forma Plant Additions and Retirements (page 8.6), Depreciation and Amortization Reserve (page 6.2), and Depreciation and Amortization Expense (page 6.1), respectively. The impact of this sale was reflected in the Company's rebuttal filing in the 2011 GRC.

Deseret Power's Portion of Hunter Assets Removal – This adjustment removes the capitalized costs pertaining to Deseret Power's ownership share of the Hunter Unit 2 scrubber and turbine upgrade from the Company's filing. The depreciation expense is removed in the Depreciation and Amortization Expense Adjustment (page 6.1).

Condit Hydroelectric Asset Decommissioning – The Company has begun decommissioning its Condit hydroelectric project after receiving final regulatory approval from FERC in June 2011. The initial breach and draining of the reservoir occurred on October 26, 2011. Demolition of the remaining portion of the dam is scheduled to begin in spring 2012 and be completed by August 31, 2012. Restoration work throughout the former reservoir area is planned to be completed by the end of 2012. This adjustment removes the O&M expense related to the Condit plant. The adjustments to electric plant in service, depreciation reserve, and depreciation expense are reflected in the adjustments to Pro Forma Plant Additions and Retirements (page 8.6), Depreciation and Amortization Reserve (page 6.2), and Depreciation and Amortization Expense (page 6.1), respectively. A similar adjustment to remove the Condit plant from results was included in the Company’s rebuttal filing in the 2011 GRC.

Goose Creek Switching Station Removal – 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 to the Decker 230 kV substation near Decker, Montana. The sale of the transmission line resulted in the Goose Creek switching station no longer being useful to the Company, and the assets were removed in October 2011. This adjustment reduces rate base by the net book value of the switching station assets. The depreciation expense is removed in the Depreciation and Amortization Expense Adjustment (page 6.1). A similar adjustment was included in the 2011 GRC.

Q. Does this conclude your direct testimony?

A. Yes.