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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES AND A PRICE INCREASE OF $32.7 MILLION, OR APPROXIMATELY 15.0 PERCENT	))))))))	**CASE NO. PAC-E-11-12** **Direct Testimony of Steven R. McDougal**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-11-12

May 2011

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

A. My name is Steven R. McDougal, and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah, 84111. I am currently employed as the Director of Revenue Requirements for the Company.

Qualifications

Q. Briefly describe your educational and professional 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. 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. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony before the Idaho Public Utilities Commission, the

Utah Public Service Commission, the Washington Utilities and Transportation Commission, the California Public Utilities Commission, the Oregon Public Utilities Commission, the Wyoming Public Service Commission, and the Utah State Tax Commission.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. My direct testimony describes the calculation of the Company's Idaho revenue requirement and the rate relief requested, based upon the Company's cost of service filing. Specifically, I provide testimony on the following:

- Calculation of the $32.7 million retail revenue increase requested in this case, representing the increase over current rates required for the Company to recover the costs incurred to serve Idaho customers;
- Inter-jurisdictional allocations, including utilization of 2010 Protocol and treatment of Idaho's Irrigation Load Control Program costs and other Class 1 demand side management ("DSM") costs;
- A description of the Test Period proposed in this case, including the treatment of rate base and jurisdictional loads;
- The results of operation for the Test Period, demonstrating that under current rates the Company will earn an overall return on equity ("ROE") in Idaho of 5.3 percent, which is significantly below the return on equity requested in this case and the current authorized return; and
- Calculation of the Load Change Adjustment Rate ("LCAR") based on costs in this filing for use in the Energy Cost Adjustment Mechanism

("ECAM").

In addition to supporting the Company's revenue requirement, I discuss a number of items that were addressed by the Commission in Case No. PAC-E-10-07 (the "2010 General Rate Case") and explain their treatment in this case. I also describe two accounting changes included in the Company's filing: (1) elimination of captive insurance coverage, replaced with self-insurance accruals on a state specific basis; and (2) accelerated depreciation of certain hydro generation facilities on the Klamath river. My testimony is accompanied by various supporting exhibits including the results of operations for the Company's proposed 2011 test period based on calendar year 2010 data, adjusted for known and measurable changes through December 31, 2011.

Revenue Increase

Q. What is the revenue increase necessary to achieve the requested return on equity ("ROE") in this case?

A. Utilizing Dr. Samuel C. Hadaway's recommended ROE of 10.5 percent produces an overall Idaho revenue requirement of $250.9 million. When compared to retail revenue at present rates an overall revenue increase of $32.7 million is needed for the Company to achieve its recommended return. Exhibit No. 2 also shows that without a rate increase Rocky Mountain Power will earn an ROE of 5.3 percent in Idaho during the Test Period. This return is far less than the 9.9 percent authorized by the Commission in the 2010 General Rate Case and the 10.5 percent ROE requested in this case.

Idaho's jurisdictional revenue requirement is determined based on the

2010 Protocol allocation methodology, which is currently being considered by the Commission. Exhibit No. 1 provides a summary of Idaho-allocated results of operations for the Test Period, and details supporting the revenue requirement by FERC account are provided in Exhibit No. 2.

Q. Please explain the main drivers causing the need for a rate increase.

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 the Company must serve existing, and reasonably anticipated customer loads. It must also comply with environmental and other regulatory and statutory requirements regarding production and transmission facilities. The actions that are taken by the Company, in this regard, are guided by the standard of "risk-adjusted least-cost," over the term of the action or investment. This means that the Company will weigh all legally mandated requirements against its obligation to provide service to the greatest extent possible at the least cost.

Company witness Mr. Gregory N. Duvall describes the increases in system-wide net power costs. The Company's application seeks to increase net power costs from $1.025 billion to $1.312 billion, which will also become the base net power costs tracked in the Company's ECAM in the future. Company witness Mr. Darrell T. Gerrard testifies regarding the transmission investments that have been made to serve customers. Company witnesses Ms. Cathy S. Woollums and Mr. Chad A. Teply testify regarding significant generation resource investments that have been required to satisfy environmental requirements as well as investments that have been made to improve the efficiency of some units. My testimony addresses the revenue requirement impact of these major projects and that of other investments across the Company.

Inter-jurisdictional Allocations

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

A. The Company's requested price increase is calculated using the 2010 Protocol inter-jurisdictional allocation that is currently before this Commission for approval in Case No. PAC-E-10-09 (the "2010 Protocol Case"). The 2010 Protocol contains proposed amendments to the Revised Protocol resulting from 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.

Q. What is the status of the Company's application for approval of the 2010 Protocol?

A. The Company filed its application on September 15, 2010, and the Case remains open for Commission consideration. On March 30, 2011, Commission Staff filed comments supporting approval of the 2010 Protocol, with the condition that the Idaho Irrigation Load Control Program be treated consistent with the Commission's order in the Company's 2010 General Rate Case.[1]

The Company filed reply comments on April 15, 2011, agreeing to the Staff position, and the Company's filing in this general rate case is made consistent with Staff's comments. However, because the Commission has not yet

[1]Monsanto also filed comments on March 30, 2011.

approved the 2010 Protocol, the Company's filing in this case may need to be updated to reflect the final outcome of the 2010 Protocol Case.

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

A. 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 changing 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. As agreed to in the Company's reply comments in the 2010 Protocol Case, Tabs 11 and 12 of Exhibit No. 2 provide the test period results using the Revised Protocol and Rolled-In allocation methodology for comparison purposes.

Q. Please describe the treatment of Class 1 DSM programs in this rate case.

A. In this case, the Company is treating all Class 1 DSM programs consistent with Order No. 32196 from the 2010 General Rate Case, wherein the Commission ruled that the costs associated with the Idaho Irrigation Load Control Program be system allocated. The Company currently runs three programs that are classified as Class 1 DSM programs: the Idaho Irrigation Load Control Program, the Utah Irrigation Load Control Program, and the Utah Cool Keeper program. In previous Idaho filings, the Company treated these programs as situs resources to their respective state.

Q. Please describe the treatment of the Company's Class 1 DSM programs proposed as part of the 2010 Protocol methodology.

A. As part of the Company's 2010 Protocol filing, and consistent with the filings in Utah, Oregon and Wyoming, the Company proposed treating all Class 1 DSM programs as situs, identical to their treatment under the previously approved Revised Protocol. However, Staff's comments in that Case state that "to be consistent with Order No. 32196 in Case No. PAC-E-10-07, Staff recommends a deviation be included in the Idaho Order for the system allocation of these costs." Thus, the Company is treating all Class 1 DSM programs, including the Idaho Irrigation Load Control Program, as system resources in this filing.

Q. Have other states agreed to treat Class 1 DSM programs as system resources?

A. No. Commission Staff has raised this issue to the MSP Standing Committee, and the issue is being discussed between the states. Company filings in other states continue to treat Class 1 DSM programs as situs DSM programs pending a resolution of the issue. However, as part of the 2010 Protocol settlements in Oregon and Wyoming, language was included referring to the ongoing MSP discussions on the topic. The Wyoming 2010 Protocol stipulation states:

> The Parties agree that the emerging issues related to the allocation of Class 1 DSM programs are not yet ripe for Commission action. The Parties agree that additional analysis and discussion of these issues should be undertaken in the MSP Standing Committee workgroup, and the Parties will endeavor to participate in the workgroup efforts to the extent possible, subject to the availability of resources. The Parties shall encourage the workgroup to develop a proposed resolution on these issues by the next MSP Commissioners' Forum. The Parties understand that the Company

may make a subsequent filing with the Commission to address this discrete issue.[2]

Q. Where is the system treatment of Class 1 DSM programs reflected in the Company's revenue requirement calculation?

A. There are two components of the Class 1 DSM programs that are reflected in the Company's revenue requirement, the costs and the benefits of the programs. The costs of the Class 1 DSM programs consist of the administrative costs of running the program and the credits paid to the participants of the program. On page 4.4 of Exhibit No. 2 these costs are shown to be included in the results of operations on a system ("SG") factor. On an actual basis, the benefits of the Class 1 DSM programs occur in the load reductions by state as a result of program operation. The 2010 coincident peaks in the filing were adjusted to reflect system treatment of the load curtailments from the Class 1 DSM programs, i.e. jurisdictional load does not include reductions in load caused by operating the programs in 2010. Reductions in peak loads due to the programs operating at time of system coincident peak were added back to the relevant jurisdictions so that the jurisdictions do not receive the full benefits of the program while other states pay for the costs. The calculation of the coincident peaks can be viewed in Exhibit No. 2 on page 10.13. Further discussion regarding the loads used in this filing is provided later in my testimony.

[2]Wyoming Public Service Commission Docket No. 20000-381-EA-10, Record No. 12624, Stipulation and Agreement paragraph 21, March 25, 2011

Test Period

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

A. The Company used the historical results of operations for the 12-month period ended December 31, 2010, adjusted for known and measurable changes through December 31, 2011 (the "Test Period"). As I will discuss later in my testimony, rate base is included using the end of year balances.

Q. Is the Test Period in this case consistent with test periods used by the Company in previous Idaho general rate cases?

A. Yes. The Test Period is prepared in a manner that is consistent with past Commission practice and the Company's general rate cases filed previously, including the Company's last two general rate cases, Case Nos. PAC-E-08-07 and PAC-E-10-07. The Company uses historical data and adjusts it for known events and costs or normalizes the data to reflect a test period that is as reflective as possible of the rate effective period given Idaho test period treatment.

Q. What overriding principle guided the Company's development of the Test Period in this case?

A. The primary objective in determining a test period is to develop normalized results of operations which best reflect the operating conditions during the time that new rates will be in effect (the "rate effective period"). Because Idaho has predominantly relied on historical test periods for setting rates, the Company used historical data with normalizing adjustments through December 2011 to reflect as closely as possible the rate effective period. Aligning the Test Period and rate effective period is crucial in an environment of rapidly expanding rate base and increasing net power costs in order to adequately capture the conditions that the Company will experience in providing safe and reliable electrical service during the time that service will actually be provided. To better align the Test Period with the rate effective period, and consistent with past cases and Commission treatment, the Company has calculated rate base on an end-of-period basis, including actual rate base at December 31, 2010, plus major capital additions that will be in service by December 31, 2011, reflected at the additions' full cost. Expense and revenue items related to new capital additions, including net power cost impacts, are annualized so that a full year of the cost or benefit is included in the Test Period.

Q. Does the method the Company used to calculate loads differ from the treatment used in the 2010 General Rate Case?

A. Yes. In its 2010 General Rate Case, the Company found that the metered loads reflected abnormal operating conditions that occurred in the 2009 calendar year. Specifically, a sharp reduction in irrigation and tariff contract load that was not weather related was distorting the loads. Due to this abnormality, loads were calculated using a forecasted level to better reflect the ongoing load the Company expected to serve during the rate effective period.

Q. Is this abnormality an issue in the metered loads used in this case?

A. No. The unadjusted loads in this case do not reflect such abnormal operating conditions as described above. For this reason, the Company used actual metered loads, adjusted for special contract curtailments, Class 1 DSM programs and weather in its request.

2010 General Rate Case, Order No. 32196

Q. Please describe how the Company reflected the Commission's ruling in Order No. 32196 from the 2010 General Rate Case in this filing.

A. Most directives from the Commission's Order are reflected throughout the Company's request. The treatment of a few of those items is highlighted below:

Irrigation Load Control Program Allocation – As described earlier, the Idaho Irrigation Load Control Program is treated as a system resource.

Uncollectible Revenues – Consistent with the Commission's Order, the Company adjusted its actual 2010 uncollectible expense to reflect a three-year historical average. The details of the adjustment are shown in Exhibit No. 2 on page 4.17.

Outside Services Expense –The Company adjusted the 2010 outside services expense to a three-year historical average consistent with the Commission's Order. The calculation can be found in Exhibit No. 2 on page 4.18.

Pension Expense – As directed by the Commission, the Company used a three-year average of cash contributions to the pension plan. The details of the calculation are shown on page 4.16 of Exhibit No. 2.

Supplemental Executive Retirement Plan ("SERP") Costs – In accordance with the Commission's Order, the Company's request does not contain any costs related to SERP. The removal of these costs can be viewed in Exhibit No. 2 in the Company's Wage and Employee Benefits Adjustment on page 4.3.4 and the MEHC Management Fee Adjustment on page 4.10.

Q. Is this a complete list of the items from the Commission's Order that were implemented in this Application?

A. No. Several other adjustments ordered by the Commission are included and noted throughout Exhibit No. 2.

Q. Were there any items addressed by the Commission in its Order in the 2010 General Rate Case that the Company did not reflect in this Application?

A. Yes. A few of the items that were addressed by the Commission in the 2010 General Rate Case are not implemented in the Company's Application. For these specific items, the Company respectfully requests the Commission reexamine these particular issues within the context of this general rate case and additional evidence being offered by the company. The impact that each item would have on the Company's request is provided in Tab 9 of Exhibit No. 2. Each of these items is listed below with a brief discussion or reference to the appropriate Company witness.

Idaho Disconnect Policy – The Company's Idaho disconnect policy is addressed in the direct testimony of Company witness Ms. Barbara A. Coughlin.

Wage Increases – The Company's costs associated with wage increases are discussed in the direct testimony of Company witness Mr. Erich D. Wilson.

Populus to Terminal – The Populus to Terminal transmission project is discussed in the direct testimony of Company witness Mr. Gerrard.

Coal Pile Inventory – This topic is discussed in detail in the direct testimony of Company witness Ms. Cindy A. Crane.

MEHC Management Fees – In 2010, the Company booked approximately $7.5

million to regulated accounts for the MEHC management fee. This amount includes approximately $200k for SERP costs and $1.9 million related to the Annual Incentive Plan ("AIP") costs paid to employees of PacifiCorp affiliates and billed to PacifiCorp through the MEHC management fee. In the Company's 2010 General Rate Case, the Commission approved Staff's adjustment to remove costs associated with both SERP and AIP from the MEHC management fee. In this filing, the Company removed the SERP from the MEHC management fee as shown in Exhibit No. 2 on page 4.10, but the Company included the AIP in the MEHC management fee for the Test Period. Company witness Mr. Wilson provides further support for including these costs in results. The impact of the AIP as included in the MEHC management fee is shown in Exhibit No 2. on page 9.0.

Accounting Changes

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

A. Obtaining insurance through a captive insurance policy at current rates is no longer an option. The transaction commitment to maintain captive insurance expired at the end of 2010 and the current policy expires on March 21, 2011. The captive coverage will be replaced with self-insurance coverage for third-party liability, transmission and distribution ("T&D") property, and non-T&D property. This eliminates the expense for captive insurance premiums and instead provides an accrual to state specific self-insurance reserves. These self insurance reserves will cover certain Idaho allocated O&M related damages. Capital related damages will be recovered as projects are added to rate base, consistent with other capital investments.

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

A. The coverage under the captive varied by category:

- Excess liability insurance provided indemnity for amounts the Company is legally obligated to pay for damages due to bodily injury, personal injury or property damage. The captive covered $750,000 per occurrence, in excess of a $250,000 deductible. Commercial insurance covered $175.0 million per occurrence after a deductible of $1 million.
- T&D property damage insurance covered property damage to overhead transmission and distribution lines related to both O&M and capital events. The first $25,000 damages per event were defined as a deductible and were allocated to O&M and capital. The captive then covered $10.0 million annually in excess of an annual $5.0 million aggregate deductible (over and above the $25,000 per-event deductible). There was no incremental commercial insurance for T&D property damage.
- Non-T&D property damage covered all risks of direct physical loss or damage including boiler explosion, machinery and electrical breakdown, flood and earthquake. The captive covered $6.0 million per occurrence, in excess of a $1.5 million deductible. Commercial insurance covered $400 million per occurrence after a deductible of $7.5 million.

Q. When did the change from captive insurance coverage to self insurance take effect?

A. The Company's captive insurance coverage expired 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 captive insurance coverage until March, 21, 2011, and self insurance accruals thereafter.

Q. What will be the new level of coverage for storm or casualty events?

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 reserve amounts related 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 No. 2, captive insurance premiums and coverage are assumed only through March 21, 2011. For the Test Period self-insurance accruals replace the captive premiums after March 21. The level of the self-insurance accrual is set based on the annual average of liability claims related to O&M payments by MEHC captive insurance from January 2008 through December 2010. Idaho'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 previously covered by the captive are included based on a three-year average of the net expense accrued, consistent with the Company's 2010 General Rate Case.

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

A. As shown on page 4.11.3 of Exhibit No. 2, 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 after March 21 are set based on the annual average of actual damages from April 2007 through December 2010. Damages are included in the average calculation 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) in place at the time.

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 of Exhibit No. 2 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 $562,000 in the Test Period in order to set rates at a level that will adequately cover expected storm and casualty damage below the new deductible threshold.

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

A. Each month, debits will be made to FERC account 924 – Property Insurance, with the corresponding credits booked to insurance reserves in FERC account 254 on a state-specific basis. 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 to pay for the damages incurred allocated to Idaho 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 Idaho customers in this case?

A. Overall, the Company's proposal results in a slight decrease in costs allocated to Idaho compared to the actual costs in the year ended December 2010. Page 4.11 of Exhibit No. 2 shows the Idaho-allocated impact of the adjustments for both liability and property insurance. The net Idaho-allocated expense decreases approximately $15,000.

Q. Please describe the Company's requested change to the depreciation associated with the Klamath facilities.

A. Consistent with the Klamath Hydroelectric Settlement Agreement ("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 effective 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. The impact of the change in depreciation rates is shown on page 8.12 of Exhibit 2; on an Idaho-allocated basis, depreciation expense in this case is increased by $262,161.

Q. **Please describe how the Company proposes to monitor the depreciation rates to ensure that the Klamath assets reach a net book value of zero by December 31, 2019.**

A. The Company proposes to provide the Commission an annual report regarding the composite depreciation rates related to the Klamath facilities for the previous calendar year and the rates currently in effect at year-end. This report could be provided as part of the Company's annual results of operations or as a separate filing. In this case, the Company is requesting the Commission approve the terminal date for depreciation of the assets, which will result in rates varying slightly over the remaining life as a result of potential retirements and additions required to keep the facility operational. Once approved, additional action by the Commission would not be required. The Commission can continue to monitor the rates and related depreciation expense through the Company's annual reports. If the terminal date changes in the future, the Company would include the impact in a general rate case in a similar manner as presented in the current case and seek Commission approval of that change.

Idaho Results of Operations

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 December 31, 2010. The revenue requirement components in that historical period were analyzed to determine if an adjustment was warranted to reflect normal operating conditions. The historical information was also adjusted to recognize known and measurable events, and to include previous Commission-ordered adjustments.

As stated earlier, historical rate base is calculated using end-of-period balances as of December 31, 2010. Major capital additions planned to go into service by December 31, 2011, are added based on the full cost expected to be placed into service. In order to synchronize other components of the revenue requirement, costs and benefits related to these major plant additions are included in revenue requirement on an annualized level regardless of the date the resource will go into service.

Q. Please describe Exhibit No. 2.

A. Exhibit No. 2 is Rocky Mountain Power's Idaho results of operations report (the "Report"). The Report provides totals for revenue, expenses, net power costs, depreciation, taxes, rate base and loads in the Test Period. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit No. 2 is organized.

A. The Report is organized into sections marked with tabs as follows:

- Tab 1 Summary contains a summary of normalized Idaho-allocated results of operations.
- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the year ended December 2010 and fully normalized results of operations for the Test Period by FERC account.
- Tabs 3 through 8 provide supporting documentation for the normalizing adjustments required to reflect on-going costs of the Company. Each of these sections begins with a numerical summary that identifies each adjustment made to the 2010 actual results and the adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit No. 2, which contains a lead sheet showing the adjusted FERC account(s), allocation factor, dollar amount and a brief description of the adjustment. The specific adjustments included in each of these tab sections are described in more detail below.
- Tab 9 shows the impacts of several items addressed by the Commission in the 2010 General Rate Case that are not implemented in the Company's request. More discussion on Tab 9 was provided earlier in my testimony.
- Tab 10 contains the calculation of the 2010 Protocol allocation factors.
- Tab 11 is Tab 2 restated based on the Revised Protocol allocation method.

- Tab 12 is Tab 2 restated based on the Rolled-In allocation method.
- Tabs B1 through B20 provide backup for the actual results included in tab 2.
- Tab C1 provides the Company's 2007 lead lag Study.

Tab 3 – Revenue Adjustments

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

A. **Temperature Normalization (page 3.1)** – This adjustment recalculates Idaho revenue based on temperature normalized historical load assuming average temperature patterns.

Revenue Normalization (page 3.2) – This adjustment normalizes base year revenue by removing items that should not be included to determine retail rates, such as credits from the Bonneville Power Administration ("BPA") for the Residential Exchange Program, amortization of the Sacramento Municipal Utility District ("SMUD") liability and collections related to the ECAM. The expense side of the BPA credit is removed in adjustment 5.2.

Effective Price Change (page 3.3) – This adjustment reflects the $8.1 million revenue increase which became effective on December 28, 2010, as a result of the 2010 General Rate Case. This adjustment also normalizes the pro forma effects for the $6.46 million special contract price change effective January 1, 2011, also determined in the 2010 General Rate Case.

SO2 Emission Allowances (page 3.4) – This adjustment removes revenue from the sale of sulfur dioxide ("SO2") emission allowances occurring during the base period and replaces it with the corresponding grandfathered amortization through the Test Period. Prior to the 2010 General Rate Case, these sales were amortized over a 15 year period, but in the 2010 General Rate Case the Company agreed to shorten the amortization of the remaining balances to five years. Thus, unamortized balances of sales prior to June 30, 2009, are amortized over five years to reflect this new methodology. Revenue from the sale of SO2 emission allowances after June 30, 2009, is returned to customers through the ECAM per Case No. PAC-E-08-08.

Renewable Energy Credit ("REC") Revenue (page 3.5) – Currently, California, Washington and Oregon have implemented renewable portfolio standards. Consequently, the Company does not sell these states' share of eligible RECs. Instead, the Company uses the renewable output to comply with current year or future year renewable portfolio requirements. This adjustment reflects the amount of REC revenues the Company expects during the Test Period and allocates the REC revenue among states to account for compliance in California, Washington and Oregon. Any differences between the projected REC revenues in this adjustment and actual REC revenues will be accounted for in the Company's ECAM filings as ordered by the Idaho Commission in Order No. 32196.

Wheeling Revenue (page 3.6) – During 2010 there were various transactions involving wheeling revenue that the Company does not expect to occur in the Test Period. These transactions relate to various prior period adjustments and contract terminations. This adjustment also includes pro forma wheeling revenue for the Test Period.