Docket No. 20000-___-ER-11
Witness: Brian S. Dickman

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

Direct Testimony of Brian S. Dickman

December 2011

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

A. My name is Brian S. Dickman 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 manager of revenue requirement for the Company. I have been employed by the Company since 2003 including positions in revenue requirement and regulatory affairs. Prior to joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing.

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

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

Q. What is your educational background?

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. I completed the Utility Management Certificate Program at Willamette University and I have also attended various educational, professional and electric industry-related seminars.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Idaho Public Utilities Commission, the Wyoming Public Service Commission, and the Utah Public Service Commission.

Purpose of Testimony

Q. What is the purpose of your direct testimony?

A. My direct testimony addresses the calculation of the Wyoming-allocated revenue requirement and revenue increase requested in this case. In support of this request, my testimony includes the following:

- Support for the calculation of the $62.8 million dollar overall revenue increase required for the Company to recover its total Wyoming revenue requirement of $668.8 million.
- Identification of the test period utilized in this case, the 12 month period from April 1, 2012, through March 31, 2013 (the "Test Period").
- Discussion of the 2010 Protocol inter-jurisdictional allocation methodology utilized to determine Wyoming-allocated results.
- Information on 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.
- Explanation of the process used by the Company to prepare the Wyoming results of operations for the Test Period, including a detailed explanation of the normalizing adjustments included in the case.

My testimony is accompanied by various supporting exhibits including the

detailed results of operations for the Test Period.

Revenue Requirement

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

A. Utilizing the 10.2 percent ROE recommended by Company witness Dr. Samuel C. Hadaway in this case produces an overall Wyoming revenue requirement of $668.8 million and an overall required price increase of $62.8 million. Exhibit RMP___(BSD-1) provides a summary of the Company's Wyoming-allocated results of operations for the Test Period. At current rates Rocky Mountain Power will earn an overall ROE in Wyoming of 6.2 percent during the Test Period. This return is less than the 10.0 percent included in the stipulation approved by the Commission in Docket No. 20000-384-ER-10 (the "2010 general rate case"), and is less than Dr. Hadaway's recommendation in this case. Details supporting the revenue requirement by FERC account and the allocation of the various revenue requirement components to Wyoming are provided in Exhibit RMP___(BSD-2).

Q. Does the revenue increase in this case include an increase related to base net power costs?

A. Yes. Similar to the 2010 general rate case, net power costs ("NPC") are included in the Test Period results. The Company currently recovers its NPC through Schedule 94, which also provides for deferral of a portion of the difference between actual NPC and the base NPC included in rates. As part of this Docket, the Company is proposing to reset the base NPC at the level included in the Test Period. Page 1 of Exhibit RMP___(BSD-1) shows the breakout of total revenue

requirement into the NPC and non-NPC components. Of the $62.8 million overall price increase, $32.7 million is related to the increase in base NPC and the remaining $30.1 million is related to non-NPC revenue requirement components (both figures include changes in retail revenue).

Q. Does the Test Period include revenue from the sale of renewable energy credits ("RECs") and sulfur dioxide ("SO_2") emission allowances?

A. No. As established in the 2010 general rate case, REC and SO_2 revenues are now unbundled from base rates and are included in the Schedule 93 REC and SO_2 Revenue Adjustment Mechanism ("RRA") tariff. The RRA also contains a balancing account provision to account for actual REC and SO_2 revenue beginning January 1, 2011, that is higher or lower than revenue included in customer rates. Therefore, the REC and SO_2 revenue on the Company's books during the base period is removed from Test Period results in order to compute revenue requirement excluding these unbundled items.[1] Details regarding base period REC revenue are shown on page 3.4 of Exhibit RMP___(BSD-2) and base period SO_2 emission allowance sales are shown on page 3.3 of the same exhibit.

Test Period

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

A. The Company used the pro forma results of operations for the period of time beginning April 1, 2012, and ending March 31, 2013. The Test Period was developed using historical data for the 12 months ended June 2011 as a base. Rate

[1] Deferred revenue from SO_2 emission allowance sales made prior to December 31, 2010, continues to be amortized over a seven year period according to Docket No. 20000-277-ER-07. Twelve months of amortization is included in the Test Period.

base is included using the average balance over the Test Period.

Q. Why did the Company select the year ending March 31, 2013, as the test period?

A. Paragraph 31 of the stipulation in the 2010 general rate case states:

> The Parties agree that in the Company's next Wyoming general rate case application, the Company will use and the Parties will not oppose the use of average rate base and a forecast test period ending up to 15 months beyond the month in which the rate case application is filed.

Based on a filing made in December 2011 the Company selected the year ending March 31, 2013, as the test period in compliance with the stipulation.

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

A. The Company is requesting that new rates become effective October 9, 2012, 10 months after filing the Company's application.

Q. Does the Company's case include investments placed in service after the date new rates become effective?

A. Yes. Because the Test Period extends beyond the point at which rates would become effective in this case, the projections of future capital additions include investment placed in service after rates become effective. However, the Company's Test Period addresses this issue by including rate base using average balances. This treatment is consistent the Commission's strong preference for using average rate base when a forecasted test period is proposed, as expressed in paragraph 175 of its final order concluding the Company's 2009 general rate case in Docket No. 20000-352-ER-09. This treatment is also consistent with paragraph 31 of the stipulation in the 2010 general rate case as quoted earlier in my

testimony. Due to the timing of the Test Period the average rate base balance effectively results in a point estimate for rate base as of September 30, 2012, which approximately aligns with the rate change in this case. However, because the Test Period and the rate effective period are not perfectly aligned, using average rate base also means that as the Company continues to place new investments into service after October 9, 2012, rates will still not entirely reflect the true then-current cost of providing service.

Q. Have you compared some of the revenue requirement components in this case to the outcome of the 2010 general rate case?

A. Yes. Table 1 below presents key components of revenue requirement, both in this case and in the 2010 general rate case. Table 1 highlights the three main cost components driving the Company's need for additional revenue: net power costs, capital additions (return on rate base, and depreciation/amortization expense), and operations and maintenance expense.

Table 1

Wyoming Rate Case Comparison ($ Millions)	(1)	(2)	(2) - (1)
	2010 GRC	**Current Case**	**Variance**
Net Power Costs	227.6	248.5	20.9
Hydro ECD	(1.9)	(1.6)	0.3
NPC Related Retail Revenue	(225.7)	(214.2)	11.5
Base NPC Revenue Shortfall	$0.0	$32.7	$32.7
Pre-Tax Return on Rate Base	200.4	206.6	6.2
Depreciation & Amortization	85.6	88.0	2.4
Operations and Maintenance	114.2	119.9	5.7
Administrative and General	21.4	21.6	0.2
Taxes Other Than Income	19.3	22.0	2.7
Income Taxes	(16.8)	(14.1)	2.7
Other	(21.7)	(22.0)	(0.3)
Non-NPC Related Retail Revenue	(402.4)	(391.8)	10.6
Non-NPC Revenue Shortfall	$0.0	$30.1	$30.1
Revenue Shortfall	**$0.0**	**$62.8**	**$62.8**
Rate Base:	1,782.0	1,839.1	57.0
Allocation Factors:			
System Generation (SG)	15.84%	15.39%	-0.45%
System Energy (SE)	17.67%	16.91%	-0.76%
Test Period	December 2011	March 2013	

Q. Why are Wyoming's load-based inter-jurisdictional allocation factors lower than they were in the 2010 general rate case?

A. The load-based inter-jurisdictional allocation factors are a product of the load forecast used for a given test period. Company witness Dr. Peter C. Eelkema details the Company's load forecast, and his testimony explains that Wyoming's load continues to grow; however, a Wyoming industrial customer has decided to serve its large load from self-generation rather than the existing "buy-all, sell-all" arrangement. Consequently, Wyoming's total load in this case is lower than the previous case. The reduced load impacts Wyoming revenue requirement in three areas: allocation factors, retail revenue, and net power costs. Wyoming's

allocation of costs is reduced, and so are Wyoming retail revenue and total net power costs.

Q. Have you done another comparison of key revenue requirement components that does not reflect the drop in Wyoming's allocation factors?

A. Yes. The comparison in Table 2 below is done in a way to isolate real cost increases without the impact of reduced allocations. Each of the key drivers in this case is shown first at the total Company level. An allocation of each component to Wyoming is calculated by applying the percentage allocation from the 2010 general rate case by category (e.g. Wyoming-allocated NPC compared to total company NPC) to amounts in both cases to avoid impacting the comparison of allocated totals.

Table 2

Case Comparison Excluding Allocation Changes
($ Millions)

	(1) 2010 GRC	(2) Current Case	(2) - (1) Variance
Total Company			
Rate Base	$ 12,300.9	$ 12,946.7	$ 645.8
Pre-Tax Return on Rate Base	$ 1,377.7	$ 1,450.0	$ 72.3
Depreciation & Amortization	$ 593.0	$ 615.3	$ 22.3
Net Power Costs	$ 1,303.2	$ 1,495.8	$ 192.6
Operations and Maintenance	$ 829.9	$ 900.7	$ 70.8
Approximate Wyoming Allocation (Using Current Case Allocation)			
Rate Base	$ 1,782.0	$ 1,875.6	$ 93.6
Pre-Tax Return on Rate Base	$ 200.4	$ 211.0	$ 10.5
Depreciation & Amortization	$ 85.6	$ 88.8	$ 3.2
Net Power Costs	$ 227.6	$ 261.2	$ 33.6
Operations and Maintenance	$ 114.2	$ 124.0	$ 9.7

The comparison in Table 2 confirms that the key drivers of the need for a rate increase in this case are net power costs, capital additions, and operations and maintenance expense.

Inter-Jurisdictional Allocation

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

A. The Company's Wyoming-allocated revenue requirement is calculated using the 2010 Protocol inter-jurisdictional allocation as described in the stipulation approved by the Commission in Docket No. 20000-381-EA-10 ("MSP Docket") on July 7, 2011. After the Commission approved the stipulation in the MSP Docket, the Company utilized the 2010 Protocol to compute the revenue requirement approved by the Commission to set rates in the 2010 general rate case. My testimony discusses how several aspects of the 2010 Protocol were dealt with in calculation of Wyoming revenue requirement in the current case, including the rate mitigation cap, Hydro Embedded Cost Differential ("ECD"), Klamath dam removal surcharge, and Class 1 Demand Side Management ("DSM") programs.

Q. Please explain the rate mitigation cap.

A. Included in the stipulation on the 2010 Protocol is an agreement to limit the impact of the 2010 Protocol on Wyoming customers relative to the previously utilized Revised Protocol allocation method. The stipulation states:

> In order to mitigate risks associated with the potential rate impacts on Wyoming customers, in Docket No. 20000-384-ER-10 and for all Company rate filings filed in 2011 and before December 31, 2012, the change in the Wyoming total revenue requirement (as

> finally determined by the Commission in each proceeding) as a result of the implementation of the 2010 Protocol shall be capped at plus or minus 0.70 percent of the company's Wyoming revenue requirement calculated under the Revised Protocol (as modified in Attachment 2 to this Stipulation).

Q. Does the rate mitigation cap impact the Company's requested price increase in the current case?

A. No. As shown on Page 1.1 of Exhibit RMP___(BSD-2) Wyoming's revenue requirement under the Revised Protocol methodology plus 0.70 percent is $670.3 million, which is greater than the Wyoming revenue requirement of $668.8 calculated using the 2010 Protocol. Consequently, the rate mitigation cap is not triggered and accordingly does not affect the Company's requested price change in this case.

Q. Please describe how the Hydro ECD is calculated in the Company's filing.

A. The Hydro ECD is calculated by comparing the cost per megawatt hour of the Company's west-side hydroelectric resources (including Mid-Columbia purchases) to the cost per megawatt hour of all other resources that were part of the Company's resource portfolio prior to the year 2005. The cost differential is then allocated to the Company's jurisdictions that were part of Pacific Power prior to the merger with Utah Power in 1989. In accordance with the 2010 Protocol stipulation, the costs of the hydroelectric and all other pre-2005 resources are updated to reflect test period cost elements. Details are provided on page 11.23 of Exhibit RMP___(BSD-2).

Q. Were any inter-jurisdictional allocation issues left unresolved by the stipulation and Commission order in the MSP Docket?

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 Revised Protocol and the approved 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. 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]

The Commission confirmed that "additional analyses and discussions" were imperative in paragraph 54 of its order approving the 2010 Protocol stipulation.

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

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 2010 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 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. Does the Company's transmission rate case include a proposed tariff to cover the cost of integrating non-owned wind resources onto PacifiCorp's transmission system?

A. Yes. The Company's FERC rate case proposes updated charges under Schedule 3 and new Schedule 3A to provide for generator regulation and frequency response service. Schedule 3 recovers the cost of this service from transmission customers with generation and load in the Company's control area while Schedule 3A

recovers the cost of this service from transmission customers who export generation out of the control area. If approved by FERC, Schedules 3 and 3A are designed to produce revenue to cover the cost of integrating third-party wind resources. The lack of such a tariff has been raised by intervening parties in previous Company general rate cases in Wyoming.

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 anticipates commencing 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 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 Wyoming 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 defer the impact on Test Period wheeling revenue related to the transmission rate case, including revenue received pursuant to Schedules 3 and 3A, and to return the difference

plus interest at the customer deposit rate to customers as an offset to the next ECAM filing made after a FERC decision is issued. 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 $460,000 on a Wyoming-allocated basis.

Wyoming Results of Operations

Q. Please explain how the Company developed the results of operations 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 was warranted to reflect normal operating conditions going forward. The historical information was adjusted to recognize known, measurable and anticipated events and to include previous Commission-ordered adjustments. In certain instances the Company compared actual costs to costs budgeted for the Test Period and provided supporting details for the incremental difference (either higher or lower than actual experience).

Q. What is the significance of the Company's method of beginning with historical information?

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

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

A. Historical retail revenue is adjusted to reflect the current Commission-approved tariff rates applied to the Test Period load projection. The testimony of Company witness 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 as described by Company witness Mr. Gregory N. Duvall. Historical operations and maintenance expenses were split into labor and non-labor components. Non-labor costs were adjusted for inflation using nationally-recognized IHS Global Insight inflation indices and for other distinct changes required to reflect conditions expected during the Test Period. Historical labor costs were also adjusted for expected changes through the Test Period. Specific adjustments are described in greater detail later in my testimony and exhibits.

Revenue Requirement Exhibit

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

A. Exhibit RMP___(BSD-2), which was prepared under my direction, is Rocky Mountain Power's Wyoming results of operations report ("the Report"). The base period for the Report is the 12 months ended June 30, 2011, which has been normalized and used to calculate the revenue requirement for the Test Period, the 12 months ended March 31, 2013. The Report provides totals for revenue, expenses, depreciation, net power costs, taxes, rate base and loads in the Test Period. Operating results for the period are presented both in terms of return on rate base and ROE.

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

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

- Tab 1 Summary contains a summary of Wyoming-allocated results according to the 2010 Protocol allocation methodology.
- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the year ended June 2011 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. The contents of each of these tabs are described in more detail below.
- Tab 9 is Tab 2 restated with the Wyoming allocation based on the

Revised Protocol allocation method in compliance with the Commission order in the MSP Docket.

- Tab 10 is Tab 2 restated with the Wyoming allocation based on the Rolled-In allocation method in compliance with the Commission order in the MSP Docket.
- Tab 11 contains the calculation of the 2010 Protocol inter-jurisdictional allocation factors. Factors in this case are based on the load forecast through March 2013 and pro forma account balances.

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___(BSD-2), 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 March 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 regulatory results including SMUD regulatory liability amortization and out-of-period revenue. Test Period revenue reflects the recent changes to base rates approved in the 2010 general rate case effective September 22, 2011.

Wheeling Revenue (page 3.2) – This adjustment reflects the level of wheeling revenue for the 12 months ending March 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.

SO_2 Emission Allowances (page 3.3) – Over the years the Company's annual revenue from the sale of SO_2 emission allowances has been uneven. Consistent with the stipulations approved by the Commission in the 2007 and 2010 general rate cases (Docket Nos. 20000-277-ER-07 and Docket No. 20000-384-ER-10), revenue from sales of emission allowances completed prior to December 2010 is amortized over a seven-year period for purposes of setting rates in Wyoming. Wyoming's allocated share of revenue from sales completed after December 2010 will be passed back to customers through the RRA.

REC Revenue (page 3.4) – This adjustment removes actual sales booked in the base period ended June 2011 for purposes of setting base rates. As discussed earlier, Wyoming's share of revenue from the sale of RECs will be accounted for through the RRA (Schedule 93). Schedule 93 will be adjusted annually to credit

customers for projected REC sales and to true up any differences between previous projections and actual REC sales. Wyoming's allocated share of REC revenue is determined according to the 2010 Protocol, including a reallocation of revenue initially allocated system wide to reflect compliance with state renewable portfolio standards.

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.

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 – 4.0.4) 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___(BSD-2), 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.

Page 4.2.1 of Exhibit RMP___(BSD-2) 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 4.2.12.

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, 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.

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 results. Details on the specific items in the adjustment can be found on page 4.4.1.

Pension Curtailment (page 4.5) – The Commission's order in Docket No. 20000-336-EA-08 allowed the deferral and amortization of: (1) the pension curtailment gain resulting from employees electing to participate in a 401(k) retirement option; and (2) the deferral and amortization of the increase in the pension and other postretirement welfare expense caused by the change in the

annual measurement date mandated by FAS 158. The deferral is being amortized over a three year period, beginning January 1, 2009, and ending December 31, 2011. Since the amortization will be completed prior to the start of the Test Period, this adjustment removes the regulatory asset balance and the amortization from results.

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 Wyoming these costs are recovered through the Customer Efficiency Service Charge, Schedule 191.

Uncollectible Accounts (page 4.7) – This adjustment normalizes uncollectible accounts expense based on a three-year average of the Company's uncollectible rate (Wyoming uncollectible accounts expense in FERC account 904 divided by Wyoming general business revenues). The uncollectible rate was calculated for each of the 12 month periods ended June 2009, June 2010 and June 2011. These uncollectible rates were then averaged and the average rate was applied to the normalized Wyoming general business revenues in this case to arrive at the Test Period level of uncollectible expense. This treatment is similar to the methodology used in the Company's rebuttal filing in the 2010 general rate case.

Wyoming AMR Savings (page 4.8) – In May 2011, the Company began expanding its Automated Meter Reading (AMR) program in Wyoming, installing over 57,000 new meters in the cities and surrounding areas of Laramie, Casper, Lovell, Riverton, Rawlins, Worland, Evanston, Kemmerer, Pinedale, Thermopolis

and Cody. The meters enable the Company to remotely obtain energy usage information and take full advantage of a proven technology to increase effectiveness and efficiency, improve customer satisfaction and reduce safety exposures for employees. This adjustment reflects the reduction in meter reading expense the Company anticipates through March 2013 as a result of the program expansions. The associated meter additions and retirements are included in Pro Forma Plant Additions (page 8.6) and Plant Retirements (page 8.7).

Insurance Expense (page 4.9) – 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 MEHC captive insurance on March 21, 2011. Injuries and damages expense is set at the three-year historical average of booked accruals net of related receivables. 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.

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 treatment for insurance expense, including the expiration of the captive insurance coverage, was included in the 2010 GRC.

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

Generation Overhaul Expense (page 4.10) – 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. A four-year average is consistent with the normalized outages assumed in the GRID model to compute Test Period net power costs.

Incremental O&M (page 4.11) – 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. Dana M. Ralston and Mr. Mark R. Tallman.

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___(BSD-3).

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___(BSD-2), 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 since 1968. The current contract associated with this arrangement expires on 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 the Great Salt Lake Minerals Company to maintain its operations. Since the plant no longer produces energy due to the generator failure, this adjustment removes the steam revenue and plant O&M expense, and no energy from the plant is included in the NPC study. The asset balance is removed in the Plant Retirements Adjustment (page 8.7); 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 it was completed in January 2011. The benefit of the settlement has been reflected in the Company's Wyoming general rate cases since the 2008 case, Docket No. 20000-333-ER-08.

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___(BSD-2), 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. 20000-257-EA-06, effective January 1, 2008. Depreciation expense also includes the accrual for hydro decommissioning as approved in Docket No. 20000-257-EA-06. Details are provided on pages 6.1.2 through 6.1.15.

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 Plant Retirements Adjustment (page 8.7). 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 March 31, 2013, detailed on pages 6.2.2 to 6.2.11. 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___(BSD-2), 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 March 31, 2013. Projecting property taxes gives 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___(BSD-4) 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 Service Code Sec. 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. 20000-352-ER-09, 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. 20000-367-EA-10, this adjustment recognizes the amortization of the regulatory asset related to the Medicare tax deferral for the Test Period.

Pro Forma Schedule Ms (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.

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 $1.00 per megawatt hour generation tax will be incured 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 agreed to in the stipulation in Docket No. 20000-352-ER-09, a regulatory asset equal to 70 percent of the revenue requirement impact on that case related to the difference in the deduction for repairs recognized in regulatory results versus recognized for tax return purposes for 2009 and 2010 years is added to rate base and will be amortized over a period of four years.

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___(BSD-2), 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 2007 information. The Company's past three general rate cases relied on this same lead lag study. Based on the results of the lead lag study the Company experiences 2.93 net lag days in Wyoming and requires a cash working capital balance of $3.8 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.

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 March 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 (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. The accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements as described earlier. Descriptions of large individual projects are included on pages 8.6.16 through 8.6.22.

The stipulation in the 2010 general rate case established a new process to allow interested parties the opportunity to conduct a review of certain environmental projects prior to those projects being constructed. As a result, the Company agreed to submit Certificate of Public Convenience and Necessity ("CPCN") filings for all environmental projects that meet certain criteria as specified in the stipulation. Table A2 in Attachment A of the stipulation listed several projects that were out of the scope of the CPCN process because they did not meet one or more of the criteria listed in the stipulation. Company witness Mr. Chad A. Teply provides testimony and supporting exhibits related to these capital

projects at Naughton Unit 1, Dave Johnston Unit 4, and Hunter Units 1 and 2.

Plant Retirements (page 8.7) – Composite plant retirement rates were applied to pro forma plant balances included in this filing to reflect ongoing asset retirements through the Test Period. This adjustment reflects these retirements into results for the gross electric plant in service. A corresponding entry to accumulated depreciation and amortization is included in the calculation of Test Period reserve balances in the Depreciation and Amortization Reserve Adjustment (page 6.2).

Miscellaneous Rate Base (page 8.8) – The Company's coal plant fuel stock balance is rising due to an increase in the cost of coal and the number of tons stored at each site. This adjustment reflects the increase in the fuel stock balance into results 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 base period includes approximately $25.0 million in plant held for future use related to the acquisition of the Cottonwood coal lease. This adjustment includes an additional $2.0 million for development costs at the Cottonwood coal lease through the Test Period. Additional detail regarding the acquisition of the Cottonwood coal lease is provided in the testimony of Company witness Ms. Cindy A. Crane.

Powerdale Hydro Removal (page 8.9) – This adjustment removes costs related to the Powerdale hydroelectric plant from results. 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 Wyoming Public Service Commission in Docket No. 20000-268-EA-07. The unrecovered plant regulatory asset was fully amortized in December 2010, and the decommissioning regulatory asset was fully amortized in March 2011.

Regulatory Asset Amortization (page 8.10) – 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, Grid West amortization expense, MEHC transition costs, Goodnoe Hills and Lake Side liquidated damages, Cholla transaction costs, electric plant acquisition adjustment, and weatherization assets. This adjustment also removes the amortization of the Oregon independent evaluator fees that are recovered by Oregon customers but were allocated system-wide in the base period.

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 of Klamath-related assets, allocation of the KHSA dam removal surcharge, and incremental O&M related to implementing the terms of the agreement. A similar adjustment was included in the 2010 GRC.

Depreciation of existing Klamath facilities is accelerated beginning

January 1, 2011, so that assets are fully depreciated by December 31, 2019. Capitalized relicensing and settlement process costs are also amortized beginning January 1, 2011, at a rate that will achieve a zero net book value by December 31, 2019. A comparison of the depreciation rates for existing Klamath facilities is shown on page 8.11.3, including the rate used prior to January 2011, the rate used to compute Test Period depreciation, and the rate based on the assets' net book value as of September 2011. Depreciation rates of existing Klamath facilities 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.

In accordance with the 2010 Protocol stipulation the KHSA dam removal surcharge is initially system allocated, but it is then re-allocated to be assigned to Oregon and California through the Klamath surcharge adjustment included in the 2010 Protocol embedded cost differential.

The testimony of Company witness Mr. Tallman provides detail regarding the Klamath O&M required for the Test Period.

Wyoming Incremental Reliability (page 8.12) – The Company has agreed to reliability improvements in Wyoming through commitments made to the Wyoming Commission and in the settlement in the 2010 general rate case. This adjustment recognizes the increased expenditures the Company will incur during the Test Period in order to achieve these reliability improvements. Please refer to

the testimony of Company witness Douglas N. Bennion for additional details.

Coal Stripping EITF 04-6 (page 8.13) – This adjustment aligns the costs of coal stripping with the extraction of uncovered coal consistent with the stipulation approved by the Commission in Docket No. 20000-352-ER-09. Stripping costs are deferred as a regulatory asset serving much like a fuel inventory account and expensed as the coal is extracted from the mine and delivered to the Company for use at its plants. This adjustment walks the regulatory asset balance through the Test Period, and the related impact to fuel expense is accounted for in the Net Power Cost Study (page 5.1).

Miscellaneous Asset Sales and Removals (page 8.14) – 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.

BHP Transmission Asset Sale – 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 2010 GRC.

Snake Creek Hydroelectric Asset Sale – 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 and imputes the gain realized on the sale of the asset. The impacts of the sale on electric plant in service, depreciation reserve and depreciation expense are reflected in the adjustments to Plant Retirements (page 8.7), Depreciation and Amortization Reserve (page 6.2), and Depreciation and Amortization Expense (page 6.1), respectively.

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 Plant Retirements (page 8.7), Depreciation and Amortization Reserve (page 6.2), and Depreciation and Amortization Expense (page 6.1), respectively.

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 2010 GRC.

Conclusion

Q. Do you believe the proposed revenue increase supported by your calculation of revenue requirement is in the public interest?

A. Yes. The Company's proposed revenue increase is in the public interest because it balances the needs of customers and the Company by setting rates at a level commensurate with the reasonable and prudent cost of providing safe and reliable service when those rates will be in effect.

Q. Does this conclude your direct testimony?

A. Yes.