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

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

Q. Are you the same Steven R. McDougal who has previously testified in this proceeding?

A. Yes.

Purpose of Testimony

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

A. My rebuttal testimony will respond to the pre-filed direct testimony filed by the intervening parties regarding the Company's revenue requirement. My rebuttal testimony explains and supports the Company's revised overall revenue increase request of $84.5 million, reduced from the $99.8 million request filed by the Company in response to the Commission order on February 14, 2008 requesting the Company revise its rate case using a December 31, 2008 test period. My testimony provides the following:

- A detailed calculation of the $84.5 million requested revenue increase, including a summary of the differences between the $99.8 million request and the current amount. The revised request includes the impact of adjustments proposed by other parties that the Company has accepted.
- The Company's response to certain revenue requirement adjustments

proposed by intervening parties in this case which the Company believes should not be adopted by the Commission. Many of these adjustments are done with little or no basis, are inconsistent in amortization, and selectively adjust accounts to a historical average when the accounts are increasing, but leave them at the projected amounts when the accounts are decreasing. These inconsistencies are designed to reduce revenue requirement and do not give the Company a reasonable opportunity to earn its authorized return on equity.

Required Revenue Increase

Q. What price increase is required to achieve the requested return on equity in this case?

A. As shown on Page 1.0 of Exhibit RMP___(SRM-1R-RR), an overall price increase of $106.9 million is required to produce the 10.75 percent return on equity requested by the Company based on the December 31, 2008 test period.

Q. Is the Company requesting the full $106.9 million required to earn a 10.75 percent return on equity?

A. No. The Company has reflected the Rate Mitigation Cap as approved by the Commission and which is described in my direct testimony. The Rate Mitigation Cap decreases the revenue increase requested in my revenue requirement rebuttal testimony to $84.5 million.

Q. Other than the impact of the rate mitigation cap described above, will the revised revenue requirement allow the Company the opportunity to earn a 10.75 percent return on equity?

A. No. The revised request will allow the Company the opportunity to earn its authorized return based on costs for the twelve months ending December 31, 2008, not the costs the Company anticipates during the time these rates are in effect. The Company anticipates a higher revenue requirement during the rate effective period than is being requested in this case. Company witness Mr. Walje addresses the problems created by the Commission's test period order in the face of rising power costs and increased investments, and the need for an approach to ratemaking that matches the level of rates with the rate effective period in order to enable the Company to have a chance of earning its allowed rate of return.

Q. Please describe the calculation of the revised overall revenue increase.

A. The Company's revised revenue increase of $84.5 million was calculated using the same allocation methodology and factors included in the original case and incorporates certain adjustments proposed by other parties. In support of the revised calculation, the following exhibits have been included in the Company's rebuttal filing:

- Exhibit RMP___(SRM-1R-RR) shows the revised revenue requirement requested by the Company. This Exhibit updates Tabs 1, 2, 9 and 10 in Exhibit SRM-1S and adds a new Tab 11 containing backup pages for each adjustment made to the Company's filing.
- Exhibit RMP___(SRM-2R-RR) is a summary of the adjustments proposed

by intervening parties being accepted in whole or in part by the Company. These adjustments are included in the revised revenue requirement in Exhibit RMP___(SRM-1R-RR).

Revenue Requirement Revisions

Q. Please identify the revenue requirement adjustments proposed by intervening parties that the Company agrees to accept either in full or in part.

A. The following adjustments have been made to the Company's revenue requirement. Each is described later in my testimony.

		Capped Revenue Requirement
Requested Revenue Increase		**99,834,407**
11.1	Remove Clark Storage Agreement Revenue Credit	2,669,642
11.2	Wind O&M - Glenrock, Seven Mile Hill	(550,445)
11.3	Generation Overhaul Expense	(2,829,866)
11.4	Powerdale Decommissioning	806,029
11.5	Labor - Merit Increases	(194,305)
11.6	AMR Labor Reductions & Remove Offset	(519,327)
11.7	Injuries and Damages	(1,666,806)
11.8	Property Taxes	(1,178,445)
11.9	Lease Expense	(385,743)
11.10	Outside Services, Out of Period Non-Recurring	(392,966)
11.11	Company Plane	(48,527)
11.12	Advertising Expense	(281,054)
11.13	Customer Accounting, Out of Period Non-Recurring	(51,149)
11.14	Remove Sierra Club Lawsuit Settlement Fees	(227,171)
11.15	Dues and Membership Fees	(43,603)
11.16	Net Power Costs	(2,881,785)
11.17	Capital Additions	(8,406,934)
11.18	Deferred Income Taxes	(87,698)
11.19	Domestic Production Activities Deduction	964,313
Rebuttal Request		**84,528,566**

Note: the above table shows the impact on capped revenue requirement related to each adjustment. The NPC amount was calculated using DPU's $1.044 billion system NPC, which the Company has adopted. Using the $1.047 billion level from the Company's revised NPC report, which as explained in the testimony of Mr. Duvall should be the starting point of any NPC adjustments, would result in a revenue requirement amount higher than the $84.5 million listed.

Adjustments Accepted by the Company

Clark Storage and Integration Agreement

Q. What is the Company's response to the Clark Storage and Integration Agreement adjustment proposed by the DPU?

A. The Company agrees with the DPU proposal to remove the revenue credit associated with the Clark Storage and Integration Agreement. This agreement expired on December 8, 2007, and the Company will not receive any revenue associated with the agreement during the test period. The Company identified this issue in response to DPU data request 45.2. This adjustment is detailed on page 11.1 of Exhibit RMP___(SRM-1R-RR).

Wind O&M – Glenrock and Seven Mile Hill

Q. Please explain the adjustment to the Glenrock and Seven Mile Hill wind plant operation and maintenance expenses.

A. Witnesses for the DPU, CCS, and UAE proposed an adjustment to remove the Glenrock and Seven Mile Hill operation and maintenance (O&M) expenses from the revenue requirement because there will no O&M expenses associated with either project in 2008.

Q. Does the Company accept this adjustment?

A. Yes. In response to DPU data request 38.2 the Company states that based on updated projections for the in-service dates for these two projects there will not be any operation and maintenance expenses for Glenrock and Seven Mile Hill during the test year. This adjustment is shown on page 11.2 of Exhibit RMP___(SRM-1R-RR).

Generation Overhaul Expense

Q. In Exhibit CCS 2.8, Ms. DeRonne proposes to adjust generation overhaul expense. Please describe this adjustment.

A. Ms. DeRonne proposes to adjust generation overhaul expense included in the test period to a 4 year historical average of $28.2 million. The Company's filing included $41.4 million for overhaul expense, calculated by escalating the actual costs experienced in the base year.

Q. Is this adjustment as proposed by Ms. DeRonne appropriate?

A. Yes, but only in part. While the Company agrees that a 4 year average may be helpful in determining the level of overhaul costs to include in rates, certain modifications should be made to the adjustment as proposed by the CCS.

Q. What modifications to the adjustment proposed by the CCS are necessary?

A. First, the time periods used in calculating the 4 year overhaul average of $28.2 million are not consistent. The average was calculated using annual overhaul expense from the following 12 month periods: March 2004; March 2005; December 2006 and December 2007. This series of periods excludes 9 months of historical data from April 2005 to December 2005. In order to correctly capture the overhaul expense trends included in an average overhaul expense amount, the inputs into the average should represent a contiguous period. Second, costs in years previous to the test year should be escalated to account for inflation and be consistent with the value of the test period dollars to which they are compared. Failing to escalate the historical amounts that are used to calculate the average ignores the inflation that has occurred over the averaging period and overstates the adjustment.

Q. Do you propose any other modifications to the CCS proposed adjustment?

A. Yes. The adjustment should include a provision for overhaul expense for new generating units. An average of historical costs only captures overhaul costs for existing plants. In this case, additional overhaul expense planned for Currant Creek and Lake Side should be included. In the Company's adjustment to overhaul expense, Lake Side overhaul costs are adjusted from the level already included in the incremental generation O&M adjustment to the projected four year average. The Company's rebuttal adjustment for overhaul expense also includes the expected 4 year average of Currant Creek overhaul costs. Adjusting plant overhaul costs to a four-year average is consistent with the treatment of outages in the net power cost study.

Q. Please describe the impacts of your proposed adjustment?

A. As shown on Page 11.3.1 of Exhibit RMP___(SRM-1R-RR), calculating the 4 year average of historical overhaul costs for existing plants and including an average of expected overhaul costs for Currant Creek and Lake Side results in a total average overhaul expense of $34.9 million compared to the $41.4 million of overhaul expense included in the Company's filing. It should be noted that the $34.9 million of total average overhaul costs excludes the Lake Side overhaul costs included in the Company's incremental generation O&M adjustment. The Company's proposed adjustment is summarized on page 11.3 of Exhibit RMP___(SRM-1R-RR)

Powerdale Decommissioning

Q. Please explain the adjustment proposed by CCS witness Donna DeRonne related to the Powerdale hydro electric generating facility.

A. Ms. DeRonne proposed an adjustment to remove the deferred Powerdale decommissioning costs from rate base and also to remove any amortization of such deferred costs.

Q. Please explain why the Company included the deferred decommissioning costs and the corresponding amortization in the case.

A. At the time of filing this case, the Company had applied for an accounting order from the Commission (Docket No. 07-035-14) that would allow for the deferral of expected decommissioning costs. Accordingly, the Company included a regulatory asset for the decommissioning costs along with amortization of that asset over approximately 5 years.

Q. What did the Commission order in Docket No. 07-035-14?

A. On January 3, 2008, the Commission issued its order approving deferred accounting treatment for Powerdale decommissioning without resolving specific issues affecting revenue requirement. The Commission set a tentative amortization period of three years, with final treatment to be determined in a future rate proceeding.

Q. Do you agree with part of Ms. DeRonne's proposed adjustment?

A. Yes. Earning a return on a regulatory asset is generally reserved for situations in which the Company has expended cash and may recover those costs over an extended period. Only a small amount of cash has been expended up to this point on the decommissioning project. Consequently, for this case the Company agrees a regulatory asset for Powerdale decommissioning should not be included in rate base where it would earn a return. Another acceptable ratemaking treatment of this regulatory asset would be to include it in rate base, along with an offsetting credit representing expenditures not yet made on decommissioning activities. As expenditures are made the offsetting credit would be reduced. In the Company's rebuttal case I propose the former treatment.

Q. Do you agree that amortization of the decommissioning asset should be removed from the revenue requirement calculation?

A. No. Similar to the regulatory treatment of decommissioning for other generating plants in the Company's portfolio, the amortization of Powerdale decommissioning costs should be included in current rates. Customers receiving the benefit of generation from a particular facility traditionally pay a share of the future decommissioning costs through the depreciation of that asset. Future customers should not be expected to bear the entire cost of decommissioning a plant whose benefits were realized by previous customers.

Q. Have you made an adjustment to revenue requirement to reflect the Commission's deferred accounting order and to incorporate the changes agreed to above?

A. Yes. Page 11.4 of my Exhibit RMP___(SRM-1R-RR) details the adjustment made to reflect both the Commission's order and the partial acceptance of Ms. DeRonne's adjustment. Specifically, the regulatory asset for decommissioning costs is removed from rate base. In addition, the amortization is recalculated to span a three year period.

Labor Merit Increases

Q. UAE witness Mr. Higgins states that the pro forma labor expense in the Company's filing was annualized incorrectly. Do you agree?

A. Yes, in part. The Company's calculations included in the case treated wage increases occurring during the test period as being effective during the entire test period, effectively annualizing the pro forma period. Although there is some argument that this best reflects future expense, the Company will accept Mr. Higgins' method of calculating the pro forma wage increases to an extent. While I accept his method of calculating the impact of the pro forma wage increases, only the portion charged to expense should be included in this adjustment. Page 11.5 of Exhibit RMP___(SRM-1R-RR) shows a recalculated adjustment. The revised adjustment also includes the impact of the reduced wages on payroll taxes. The final effect of this adjustment is a $446,194 decrease to total company labor expense.

AMR Savings

Q. Please explain the adjustment proposed by CCS witness Helmuth Schultz related to automated meter reading savings.

A. Mr. Schultz has recalculated the savings expected to be realized as a result of installing automated meter reading along the Wasatch Front. His adjustment consists of two parts. First, Mr. Schultz recalculates the expected labor savings using slightly more precise figures for employee compensation and the timing of employee departures. Second, Mr. Schultz removes an offsetting cost of implementing the new system on the basis that it is non-recurring in nature.

Q. Do you agree with the proposed adjustment?

A. The Company is willing to accept this adjustment as calculated by Mr. Schultz. Mr. Schultz's calculations of labor savings are accurate, and with only the small exception of an ongoing wage increase for meter readers remaining with the Company, the majority of the cost offsets are non-recurring in nature. This adjustment is shown on page 11.6 of Exhibit RMP___(SRM-1R-RR).

Injuries and Damages

Q. Does the Company agree with a three year average of claims paid utilized by CCS witness Schultz in determining injury and damage expenses?

A. The Company sees merit in using an average to set the projected level of injuries and damages expense. However, the Company's results of operations are prepared using the accrual method of accounting and it is proper to reflect accrued expenses for injuries and damages rather than using a cash method.

Q. Does the Company record expense accruals by arbitrarily setting pre-determined estimated injury and damage reserve levels that are not backed by an actual claim event?

A. No. When an incident occurs, monetary payment of damages may not occur for years. The statute of limitations governing how long a claimant has to present a claim varies from one to six years depending upon the state and the type of damage or injury. No claim can be paid until an accrual is made. Unless a claim is made, no accrual is booked. Once a claim is presented, an analysis is made by a reserve committee to determine what the accrual should be. This reserving and establishing of an accrual is governed by FAS 5 accounting rules and Sarbanes-Oxley legislation.

Q. What is the Company's recommendation to the Commission concerning this issue?

A. The Company recommends the Commission reject this adjustment but in its place substitute the adjustment proposed by the Company below. As explained above, accrual accounting is the proper way to reflect the injury and damage expense.

Q. What does the Company recommend for an injury and damage adjustment?

A. The Company recommends the Commission accept a three year average of injuries and damages expense based on accruals booked by the Company. This adjustment is shown on page 11.7 of Exhibit RMP___(SRM-1R-RR).

Property Taxes

Q. Please explain the adjustment made to property taxes.

A. Property taxes and the associated proposed adjustment are discussed in the rebuttal testimony of Norman K. Ross. This adjustment is shown on page 11.8 of Exhibit RMP___(SRM-1R-RR).

Lease Expense

Q. DPU witness Mr. Thomson proposed an adjustment to reduce rent expense. Does the Company agree with the adjustment?

A. The Company agrees in principle with Mr. Thomson's adjustment; however, I would like to correct some of the facts upon which he relied. Of the spaces identified by Mr. Thomson, the 1033 building on 6th Street in Portland is fully utilized to house utility equipment and does not merit an adjustment. In addition, the Company's response to DPU data request 37.1 incorrectly calculated the unutilized space expected at the Sandy Training Center; a supplemental response correcting the calculation has been submitted by the Company. Correcting the calculation results in a greater reduction to rent expense for that facility than recommended by Mr. Thomson. The revised adjustment reflects updated amounts of unutilized office space, removes the net cost for certain office space that is subleased below the Company's cost, and removes leases that expire prior to the end of the December 2008 test period. However, the cost of the lease for the 1033 building in Portland is not removed. This adjustment is shown on page 11.9 of Exhibit RMP___(SRM-1R-RR).

Outside Services – Account 923

Q. What is the adjustment Mr. Thomson proposes to FERC account 923 – Outside Services?

A. In his audit of FERC account 923, Mr. Thomson identified various items for removal from the Base Period (12 months ended June 2007). The total identified for removal was $1,312,461 on a total Company basis, or $553,990 Utah allocated. He states that the items are either non-recoverable, prior period or non-recurring expenses.

Q. Does the Company agree that these expenses should be removed based on Mr. Thomson's analysis?

A. Yes, in part. The Company agrees to remove a total of $877,346 (total company) from Account 923. The Company disagrees with the remainder of Mr. Thomson's recommendation.

Q. Which expenses does the Company agree to remove from results?

A. Please refer to DPU Exhibit 4.3.1. The Company agrees to remove items 2) Hewitt & Associates for $548,456, 3) Jeremy Weinstein for $22,889, 4) Watson Wyatt for $12,242 and 6) Smith Barney for $75,267. In addition, the Company agrees to remove $15,700 of the $78,501 recommended by Mr. Thomson for item number 7) Cascade Direct. For item 5) Net G, the Company agrees to remove $202,792, a larger amount than Mr. Thomson recommended. This is summarized on page 11.10.1 of Exhibit RMP___(SRM-1R-RR).

Q. What is the Company's position on the remaining items proposed by Mr. Thomson?

A. The Company believes that the remaining expenses identified by Mr. Thomson should remain in the revenue requirement. Listed below are the adjustments with which the Company disagrees:

1) Scottish Power Holding – Mr. Thomson recommends removing an entry that was booked on July 31, 2006 to pay an invoice, claiming it was an out of period expense. However, a $210,000 entry to reverse the accrual was also booked in the base period. This should also be removed. Removing both items results in a net impact of zero.

5) Net G – The Company entered into this service contract to support the eLearning training system. On January 1, 2008, the amount owing on this contract was reduced to $87,208. Mr. Thomson recommends removing $120,833 of the original $290,000 that was booked. However, after further review, the Company believes the amount should be reduced at a greater level to $87,208, the current balance owed, which would remove a total of $202,792 on a total company basis.

7) Cascade Direct – This pertains to rebranding advertising expense associated with changing the name of the Company to Rocky Mountain Power. The Company believes that only $15,700 of the proposed $78,501 should be removed; the remainder was already removed in the Company's filing. In Adjustment 4.1 Miscellaneous General Expense, $618,554 of rebranding expense was removed from base period results on page 4.1.4 of SRM-1S, FERC account 930. This amount included $62,801 of the same expenses that Mr. Thomson identified in his audit.

8) KPMG – Mr. Thomson believes this $49,123 expense should be removed on the basis that it is out of period. This invoice is for an Affiliate Transaction Rules audit that KPMG conducts for the Company on an annual basis. Thus, it is an ongoing expense and should remain in results.

9) McBride Real Estate – Based on his assumption that this item was a lobbying expense, Mr. Thomson proposes to remove $13,456, an expense the Company paid as a commission on its Washington D.C. office. However, the office in Washington D.C. is utilized by the Company to conduct the Company's FERC filings. This should be included in results in order to match FERC wholesale sales and transmission revenues, which are credited to ratepayers in results of operations.

10) Sun Microsystems – Mr. Thomson proposes to remove $13,200, three months of the expense, because it is out of period. However, this is an ongoing expense and the full cost of the contract is expected to continue; therefore, the three months of expense should remain in results to maintain an annual level of the expense in results.

11) Solberg Adams – Mr. Thomson removes the cost the Company incurred to pay a $96,305 finder's fee for excise tax credits. Although the credits were derived from 2003 and 2004 tax years, the credits were refunded to the Company by the Internal Revenue Service in 2007. The ratepayers are receiving an excise tax credit benefit of more than $175,000 in FERC Account 921 in the Base Period as a direct result of this expense. Applying the matching principal, the expense to obtain the credit should remain in the Base period results

12) Donald S. Roff – This cost was incurred by the Company for its depreciation study, which the Company conducts approximately every 5 years. Mr. Thomson proposes to amortize the $90,236 expense over five years. The Company does not believe this expense should be subject to amortization due to the fact that the amortization of this expense would be immaterial and would unduly prolong rate recovery.

This adjustment is shown on page 11.10 of Exhibit RMP___(SRM-1R-RR).

Company Plane

Q. Will you explain the adjustment to expenses related to the Company plane as proposed by DPU witness Mr. Thomson?

A. Mr. Thomson removes $41,659 (total company) identified by the Company as non-utility costs in its response to DPU data request 41.1. He then proposes an additional adjustment of $128,504 total company based on his review of DPU 41.1.

Q. How did the Company identify the $41,659 in non-utility expenses?

A. In compiling the response to DPU request 41.1, the Company identified costs related to passengers or flights that served a purpose not related to above the line utility functions. The Company provided Attachment DPU 41.1-2 that listed these items along with the cost of each, which the Company agreed to remove from the rate increase requested in this case. These costs have been removed from the requested revenue requirement as shown on Page 11.11 of Exhibit RMP___(SRM-1R-RR).

Q. Do you agree with the additional costs removed by Mr. Thomson?

A. The Company believes virtually all of the additional flights identified by Mr. Thomson are appropriately classified as utility charges. However, because of the small dollar impact of this adjustment, the Company has discussed this with the DPU and has agreed to accept 50 percent of the additional amount proposed in this adjustment.

Advertising Expense

Q. Are you familiar with the adjustment proposed by Mr. Thomson in DPU-Exhibit 4.5?

A. Yes. Mr. Thomson proposes to reduce base year advertising expense by $2,880,224 on a total company basis, or $1,324,171 allocated to Utah.

Q. What is Mr. Thomson's reasoning for removing this expense?

A. In his direct testimony, Mr. Thomson states that he is reducing advertising expense due to lack of substantiation of the costs. He treats unsubstantiated costs as unrecoverable until such costs are shown to meet Utah Administrative Code: Public Service Commission R746-406 and FERC rules.

Q. What are the Public Service Commission R746-406 rules and FERC rules for advertising mentioned by Mr. Thomson in his direct testimony?

A. Utah Administrative Code: Public Service Commission R746-406 does not allow the cost of advertising that is political, promotional or institutional to be included in rates. The code states:

The term "political advertising" means advertising for the purpose of influencing public opinion with respect to legislative, administrative, or electoral matters, or with respect to an issue of public dispute. The term means advertising for the purpose of encouraging a person to select or use the service or additional service of an electric or gas utility or the selection or installation of an appliance or equipment designed to use that utility's service. The term "institutional advertising" means advertising which is designed to create, enhance, or sustain an electric or gas utility's public image or good will with the general public or the utility's customer. For purposes of this rule "political advertising," "promotional advertising," and "institutional advertising" do not include:

1. Advertising which informs consumers how they can conserve energy, use energy wisely, or reduce peak demand for energy; 2. advertising required by law or regulation, including advertising required under Part 1

of Title II of the National Energy Conservation Policy Act; 3. advertising regarding service interruption, safety measures, or emergency conditions; 4. advertising concerning employment opportunities with the utility; or 5. an explanation of existing or proposed rate schedules, or notifications of hearing thereon, or 6. information about the availability of energy assistance programs.

FERC rules require that supporting documents identify the specific advertising message and that copies of the advertising message be readily available.

Q. What information did the Company provide to the DPU regarding FERC Account 909 in its second supplemental response to DPU request 6.2 as cited by Mr. Thomson?

A. Based on discussions between the Company and the DPU, the Company provided the third supplemental response to DPU request 6.1. This response consisted of copies of invoices and documents from selected vendors as requested by the DPU. However, many of the documents did not have enough information to clearly identify the specific advertising message.

Q. Will you explain the specific items proposed to be removed from expense in Mr. Thomson's Exhibits 4.5.1 and 4.5.2?

A. Mr. Thomson proposes to remove the following advertising costs in his adjustment: $1,440,508 charged to SAP account 530056, Customer / Marketing Services; $208,091 for customer letters concerning Bonneville Power Administration (BPA) rate matters and BPA credit cancellation advertisement; $669,573 for an accounting entry made to transfer expenses from FERC Account

930.1 to FERC Account 909; $34,828 for various items that did not have message support; and $527,224 for additional unsubstantiated items. Mr. Thomson stated that if substantiation is provided that show these costs are recoverable he will modify his adjustment.

Q. Has the Company reviewed the advertising messages included in this adjustment?

A. Yes. The Company's review of the advertising messages for the items listed in Mr. Thomson's Exhibits 4.5.1 and 4.5.2 show the majority of these costs fall into categories that are allowed by R746-406.

Q. Has the Company prepared its own analysis to determine the impact of this adjustment?

A. Yes. The analysis prepared by the Company found that some costs identified by Mr. Thomson do not meet the requirements set forth previously and should be removed. This adjustment is shown on Page 11.12 of Exhibit RMP___(SRM-1R-RR).

Customer Accounting – Out of Period Non-Recurring

Q. Please provide an overview of the adjustment to customer accounting expense proposed by DPU witness Mr. Thomson.

A. Mr. Thomson proposes removing three items booked to Accounts 901 and 903. The costs consist of Express Recovery Services for $7,257, CheckFree Pay Corporation for $21,153, and Xerox Corporation for $77,312 (all total company). His argument is that each one is either out-of-period or non-recurring.

Q. Do you agree with the proposed adjustment?

A. The Company accepts Mr. Thomson's Adjustment 4.6 and agrees to the removal of the three items. However, it should be noted that the Company believes the two smaller items are normal recurring expenses. These kind of small expenses are routine bills and there are likely offsetting items that should be added to the test period. The Company is agreeing to their removal because of the small dollar amounts involved and in the interest of reducing the number of issues remaining to be decided in the case. This adjustment is shown on page 11.13 of Exhibit RMP___(SRM-1R-RR).

Sierra Club Lawsuit Settlement Fees

Q. Does the Company agree with CCS witness Ms. DeRonne's adjustment to remove expenses for settlement fees associated with a Sierra Club lawsuit involving the Jim Bridger plant?

A. Yes. Based on the Company's examination of Ms. DeRonne's analysis, it appears the appropriate treatment for these fees is to record them below the line. This adjustment is shown on page 11.14 of Exhibit RMP___(SRM-1R-RR).

Dues and Memberships Fees

Q. Please provide an overview of the adjustment to dues and membership fees proposed by DPU witness Ms. Salter.

A. Ms. Salter's adjustment removes both EPRI and WECC dues and membership fees. She proposes to remove $86,049 of EPRI membership fees on the basis that they are out of period, and $199,650 of EPRI fees because of a lack of documentation. In addition, Ms. Salter removes the entire accrual of WECC dues on the premise that $25,000 is out of period and $125,000 lacks supporting documentation.

Q. Please describe the review of Ms. Salter's proposed adjustment.

A. First, documentation was obtained to support the fees for both WECC and EPRI. For EPRI the invoices show that the fees included in the case are within the test period and are appropriately included in the Company's results of operations. The Company received two separate invoices from EPRI entitled "Second Quarter EPRI 2007 Membership," although one invoice is actually for third quarter dues and not second quarter. The Company has invoices for each of the four quarters that Ms. Salter requested.

Second, when the Company filed the case, it was still awaiting the WECC invoice that was due in February for the previous year. Since the Company has continued to accrue monthly dues, the Base Period contains more than one year of dues.

Q. Based on the Company's investigation, do you agree with the adjustment proposed by Ms. Salter?

A. Yes, in part. I agree an adjustment is warranted to remove $95,716 of WECC accruals because they are in excess of one year's WECC membership fees. I disagree with Ms. Salter's adjustment to remove EPRI membership dues because the expenses are within the base period and included at an annualized level. This adjustment is shown on page 11.15 of Exhibit RMP___(SRM-1R-RR).

Net Power Costs

Q. What changes have been made to the net power costs included in the case?

A. Total Company net power costs have been revised to $1,044 million as described in the testimony of Company witness Mr. Duvall. This adjustment has been included on Page 11.16 of Exhibit RMP___(SRM-1R-RR).

Capital Additions

Q. Mr. Croft of the DPU proposes an adjustment to rate base in his testimony. Please describe this adjustment.

A. Mr. Croft proposes to reduce plant additions included in rate base that were projected to occur between July 2007 and February 2008 by $144.0 million. This adjustment is based on the Company's response to CCS data request 16.8, which provided actual plant additions transferred to Account 101 – Electric Plant in Service from July 2007 through February 2008. Over this period, actual plant additions were $144 million less than the plant additions included in the Company's filed rate base. Mr. Croft's adjustment removes the $144 million of plant additions from rate base, along with reflecting the associated plant retirements, depreciation expense and depreciation reserve impacts. In his erratum testimony, Mr. Croft states that this adjustment reduces Utah revenue requirement by $8.7 million when using the DPU recommended capital structure.

Q. Does Mr. Croft provide any other calculations related to this issue?

A. Yes. In DPU Exhibit 7.3.0R, Mr. Croft provides an estimated deferred tax impact of this adjustment. He argues that deferred income tax expense should be increased by $112,418 as a result of this adjustment.

Q. Do you have any concerns with Mr. Croft's proposed adjustment?

A. Yes. Due to ever-changing business conditions, the Company must continually assess what investments in the system must be made in order to best meet our obligation to serve our customers. This process sometimes requires that the Company reallocate its investment budget in order to optimize the investments made to the system. From July 2007 through February 2008, the Company invested nearly $1.1 billion in its system. In addition, the rate effective period for the revenue requirement to be determined in this proceeding begins in August 2008. As a result of the Commission's order on the test period, the Company is including plant additions in this filing only through December 2008. This creates a 7 month lag between the rate base included in the filing and the beginning of the rate effective period.

Q. Are you recommending that the Commission reject Mr. Croft's adjustment?

A. No. Although the Company believes that it will invest in total what was forecast in the rate case, the methodology used in calculating the test period rate base requires that an adjustment be made. Test period rate base is calculated by averaging the monthly plant balances from December 2007 to December 2008. This methodology ensures that plant additions are included in the revenue requirement proportionately with the period in which the plant addition is in service during the test period. As explained in Mr. Croft's testimony, actual plant additions through February 2008 are understated compared to what is included in the rate case. Even if the Company invests what was forecasted in the rate case, but at a later date, the filed test period rate base will be overstated. On this basis the Company agrees in principle with Mr. Croft's adjustment.

Q. In his testimony, Mr. Croft refers to this adjustment as a form of "true-up" to the Company's forecast. Do you agree with this description?

A. No. The Company is not agreeing to this adjustment on the basis that it is a form of "true-up" to the Company's plant addition forecast. The Company is agreeing to this adjustment on the basis described above. A "true-up" adjustment would require adjusting all related components, such as net power costs and incremental O&M expense. Furthermore, if the DPU is interested in making true-up adjustments to the Company's revenue requirement, true-up adjustments should be made for all components of the revenue requirement and not just those that decrease the revenue requirement.

Q. Do you have any further concerns with this adjustment?

A. Yes. When calculating plant retirements to compute his adjustment, Mr. Croft included new generation additions. New generation additions are not expected to experience retirements for several years after the asset is placed into service. Including new generation assets in the retirement calculation overstates retirements, which in turn, understates Electric Plant in Service (EPIS). Also, the Company's examination of the plant additions revealed $(8.6) million in transactions that are allocated to non-utility plant. By including these items in his adjustment, Mr. Croft understated EPIS, overstating the impact of his proposed adjustment.

Q. Is a deferred tax calculation necessary to accurately reflect the impact of this adjustment?

A. Yes. Deferred tax impacts must be calculated in order to accurately reflect the revenue requirement impact of this adjustment. Mr. Croft calculated a deferred tax impact of this adjustment, which was provided to the Company in response to RMP data request to DPU 2.16. The impact, however, as stated above, is not reflected in the DPU's proposed revenue requirement. The Company has calculated the deferred tax impact of its rebuttal to this adjustment, which is included the Company's rebuttal adjustment 11.18 – Deferred Income Taxes.

Q. How do you propose to address your concerns with Mr. Croft's adjustment?

A. Page 11.17 of my Exhibit RMP___(SRM-1R-RR) shows the Company's calculation of the adjustment reflecting the proposed reduction to plant additions and correcting the issues described above. The deferred tax impact of this adjustment is addressed on page 11.18 of Exhibit RMP___(SRM-1R-RR).

Q. What does Mr. Brubaker propose with respect to the capital additions included in the Company's filing?

A. Mr. Brubaker proposes that the Company file an update with the Commission and parties on the status of each capital addition included in its filed rate base. The update is to include revised in-service dates and updated costs. Mr. Brubaker further proposes that adjustments should be made to the revenue requirement filing to eliminate from the revenue requirement projects that are no longer expected to be completed within the test year. Projects whose in-service dates have changed but are still scheduled to be placed into service during the test period should have their revenue requirement impact modified to reflect the updated in-service date.

Q. What is the Company's response to Mr. Brubaker's proposed update to capital projects?

A. There are two main flaws in Mr. Brubaker's proposal: 1) he proposes to adjust capital projects without adjusting other related components such as net power costs; and 2) he proposes a one-sided adjustment where projects that have been delayed are removed from revenue requirement, but new projects cannot be added.

Mr. Brubaker particularly focuses on wind projects. If wind projects are delayed, revenue requirement will be decreased because of the reduced rate base and O&M associated with the projects. However, revenue requirement should also increase because of the elimination of the zero-fuel-cost wind resource, the loss of the renewable energy tax credits and deferred income tax, and the elimination of the renewable energy credits available for sale. In order to accurately calculate revenue requirement, all of these changes should be considered.

Mr. Brubaker's adjustment is one-sided because the Company would be required to remove projects which have been delayed, but would not be allowed to include new projects. The Company is continually analyzing the capital needs of the electrical system. It is not uncommon to change priorities and accelerate a project because of a critical need, causing a delay in other projects. It would be unfair to penalize the Company for making decisions that benefit customers by allowing a one-sided adjustment as proposed by Mr. Brubaker.

Q. What other concerns do you have with Mr. Brubaker's proposal?

A. As stated above, modifying plant additions included in the filing would require the modification of several revenue requirement components, such as depreciation, net power costs, taxes and renewable energy tag sales. Such a restatement would essentially constitute the preparation of a new revenue requirement filing to properly match the revenue requirement components. The Commission-ordered procedural schedule does not allow the time necessary for the Company to prepare, and for parties to examine, the restated results that would be required if UIEC's proposal were adopted.

Q. What do you recommend regarding Mr. Brubaker's proposal?

A. I recommend that Mr. Brubaker's proposal be rejected based on the merits described above.

Deferred Income Taxes

Q. Please explain the two adjustments made related to income taxes.

A. The Company is making two adjustments related to income taxes. First, an adjustment is made to deferred income taxes reflecting an updated run of the Power Tax model. Second, an adjustment is made to recalculate the Domestic Production Activities Deduction. These two adjustments are discussed in the testimony of Mr. Jonathon D. Hale. These adjustments are shown on Pages 11.18 and 11.19 of Exhibit RMP___(SRM-1R-RR).

Adjustments Not Accepted by the Company

SO2 Allowance Sales Amortization

Q. Please describe the SO2 adjustment proposed by Mr. Higgins in UAE-WM Exhibit 1.7.

A. Mr. Higgins proposes to reduce the amortization period for SO2 allowance sales occurring after January 1, 2008, from 4 years to 3 years. He also proposes to reduce the amortization period from 4 to 3 years for deferred SO2 allowance sales with unamortized balances as of December 31, 2007.

Q. What is Mr. Higgins' rationale for changing the amortization period?

A. In his direct testimony Mr. Higgins claims that the SO2 allowance sales amortization period should be shortened to allow customers to receive the benefit over a shorter period of time. No other justification is provided as to why the change should be made.

Q. Do you agree with Mr. Higgins that the amortization period for SO2 allowance sales should be shortened to 3 years?

A. No. The Company uses between four and fifteen years for amortization of SO2 allowance sales in its various jurisdictions. The four year amortization period in Utah is already the shortest used by the Company. In Docket No. 97-035-01, the parties stipulated, and the Commission approved, that SO2 allowance sales would be amortized over a period of four years. Since that proceeding, the Company has filed four additional general rate cases in which SO2 allowance sales were amortized over four years. Mr. Higgins does not provide sufficient justification for accelerating the amortization period and departing from the precedent set by the Commission in the prior cases.

Q. What is wrong with Mr. Higgins' reasoning behind changing the amortization period?

A. The amortization of SO2 allowance sales should be viewed as a smoothing mechanism for including related revenue in results of operations; not to, as Mr. Higgins suggests, determine the rate at which SO2 allowance sales are credited to customers. Shortening the amortization period would result in increasing customers' exposure to the market conditions that drive varying levels of SO2 allowance sales from period to period.

Q. Does the Company have any additional concerns with this adjustment?

A. Yes. It appears that several errors were made in calculating and determining the revenue requirement impact of this adjustment. In calculating the deferred income tax expense impact of this adjustment on Page 2 of UAE-WM Exhibit 1.7, a tax rate of 3.795 percent was used instead of 37.950 percent, understating the deferred income tax expense impact of this adjustment by approximately $1.6 million. On Page 3 a debit was made to the Company's filed accumulated deferred income tax balance to arrive at UAE-WM's proposed balance, while the adjustment proposed on Page 1 of UAE-WM Exhibit 1.7 contains a credit to the same accumulated deferred income taxes. Page 1 of UAE-WM Exhibit 1.7 shows a debit to account 253.98 (Regulatory Deferred Sales), but this adjustment was not included in the revenue requirement calculation on Page 3 of UAE-WM Exhibit 1.7.

Q. Has the Company prepared its own analysis to determine the impact of Mr. Higgins' adjustment?

A. Yes. Calculating Mr. Higgins' adjustment corrected for the errors identified above results in a $1.8 million reduction to Utah's revenue requirement using Revised Protocol, $1.1 million less than UAE-WM's proposed $2.9 million reduction.

Q. What does the Company recommend in regard to this adjustment?

A. The Company recommends that the Commission not adopt UAE-WM's proposal and continue with the methodology that has been established and used in Utah for years.

Transmission Revenue Credit Adjustment

Q. Are you familiar with the adjustment to transmission revenue proposed by UIEC witness Mr. Brubaker?

A. Yes. Mr. Brubaker proposes to impute revenue to replace an expired transmission contract between the Company and Weyerhaeuser. He argues that the previously utilized transmission capacity should produce a revenue credit even though the Weyerhaeuser contract has terminated.

Q. Does the Company agree with the proposed adjustment?

A. No.

Q. Does the Company assume that the termination of a long-term contract correlates to an increase in short-term revenues?

A. No. Each transmission transaction is based on a unique transmission path and the Company's case includes changes to contracts and related revenue. The expiration of a long-term contract is not necessarily followed by a replacement contract along the same path. Other wholesale sales or transmission customers may have no need for the available transmission capacity, as is the case in this instance.

Q. Does the location of the transmission line used for the Weyerhaeuser contract cross a market competitive transmission path?

A. No. The Weyerhaeuser contract purchase was on an internal transmission path within the Company's system, not an external path where a customer is likely to purchase transmission rights on the line. In fact, no other wholesale sales or transmission customer has purchased the transmission capacity since the contract expired in 2006. It is an incorrect assumption on UIEC's part to assume that a terminating contract always creates additional capacity that other third parties would utilize.

Lake Side O&M

Q. Please explain the adjustment Mr. Higgins is proposing to the operation and maintenance expense for the Lake Side generating plant.

A. Mr. Higgins proposes an adjustment to remove $617,082 in total company O&M expenses related to the Lake Side plant. This reduces revenue requirement in Utah by $261,500.

Q. What is Mr. Higgins' reason for this adjustment?

A. Mr. Higgins recommends the Lake Side plant O&M expense be no greater than that projected for the test period ending June 2009.

Q. Does the Company agree that the Lake Side plant O&M expense should be no greater than what was projected for the test period ending June 2009?

A. No. In the test period portion of this case, Mr. Higgins was the main proponent for moving the case from a June 2009 test period to a December 2008 test period. But now he proposes to deviate from that test period for an individual item that happened to increase as a result of the test period change.

Q. Why is the Lake Side O&M expense higher in the December 2008 test period compared to the June 2009 test period?

A. In calendar year 2008 the Lake Side plant is scheduled to have a spring overhaul. In calendar year 2009, the Lake Side plant is scheduled to be overhauled in the fall. Because of the overhaul timing, the original test year ending June 2009 did not include any overhaul. The Company has taken this overhaul expense into account in calculating the four year average generation overhaul expense as explained previously.

Change in O&M Escalation

Q. What is the Company's position on the adjustment Ms. DeRonne proposed to the O&M escalation factors?

A. The Company strongly disagrees with this adjustment. It uses faulty logic and double counts savings already included in the rate case. Ms. DeRonne relies on Company presentations stating O&M costs will be held flat, with inflationary pressures absorbed through efficiencies. Actual non-power cost O&M expense for the June 30, 2007 base period in this case is $983 million. Fully normalized non-net power cost O&M expense in the test period is $981 million. Consistent with statements made in Company documents reviewed by Ms. DeRonne, the rate case as filed already includes O&M costs that are $2 million below the base period level. This reduction is achieved through efficiency adjustments and is offset by inflation. In addition, because of the test period ruling in this case the Company will necessarily absorb inflation between the test period and the rate effective period.

Q. What is the adjustment Ms. DeRonne proposed to the O&M escalation factors?

A. Ms. DeRonne contends in her direct testimony that the Global Insights indices do not accurately reflect the true escalation pressures the Company will experience from July 1, 2007 through December 31, 2008. Referencing sources from the Company's budgets and responses to discovery, Ms. DeRonne further states that these documents present evidence that the Company anticipates that it will not be subject to significant inflation. Based on these statements, Ms. DeRonne recommends an adjustment to uniformly decrease the escalation factors to 1.25 percent for all non-labor O&M accounts. This adjustment would result in a $13,456,104 total company ($5,856,025 Utah allocated) reduction to revenue requirement.

Q. How does Ms. DeRonne derive the 1.25 percent escalation factor?

A. According to Ms. DeRonne's testimony, this number was calculated based on the Company's 2007 - 2016 Ten Year Business Plan (MDR 2.13) which states that the Company assumes a non-labor inflation rate of 2.5 percent for FY 2007. Since one-half of calendar year 2007 was included in the Base Period, Ms. DeRonne believes one-half, or 1.25 percent is a more accurate depiction of inflation levels. She recommends that the current Global Insights factors, ranging from 1.3 percent to 5.7 percent, be replaced with an escalation factor of 1.25 percent.

Q. What do the Company's budgets and other discovery documents referenced by Ms. DeRonne in her testimony specifically say about the level of O&M expenses in 2007 & 2008?

A. The documents generally indicate that the Company's plan is to try to hold total O&M expense levels flat by absorbing inflation through labor and procurement efficiencies.

Q. Does the Company still believe this to be an accurate assessment of the O&M inflationary pressures it will experience from July 2007 through December 2008?

A. Yes.

Q. Why does the Company continue to support its use of Global Insights escalation factors to forecast O&M expense levels through December 2008?

A. The O&M expenses in the Company's budgets remain flat as a net result of savings and cost escalation. Since the MEHC merger, specific initiatives have reduced the Company's O&M expense. Concurrently, inflationary pressures have increased these expenses and are expected to continue to do so. Both the savings and the escalation are expected to continue through December 2008. It is the net effect that flattens O&M expense levels and not an absence of inflation.

Q. Are these savings included in the rate case filing as benefits to the ratepayers?

A. Yes. The December 2008 general rate case includes the savings for efficiencies related to the AMR Adjustment 4.15 and the MEHC Transition Savings Adjustment 4.11. Since ratepayers receive the benefit of these savings, it would be incorrect to remove the cost escalation.

Q. Are there any other concerns with Ms. DeRonne's proposed adjustment to the inflation rate?

A. Yes. This adjustment effectively results in a triple count of the savings associated with the MEHC-related labor reductions. These savings are included in the rate case as Adjustment 4.11 in exhibit SRM-1S. In addition, Ms. DeRonne is using these savings in this adjustment by relying on the Company statement that O&M expense inflationary pressures will be absorbed and offset by labor and procurement efficiencies. Also, Mr. Schultz uses these same labor reductions as justification for his labor adjustment. Please see the labor – employee complement adjustment later in this testimony for more on this point.

Q. What is your recommendation on this adjustment?

A. The Commission should reject it in its entirety. It is inappropriate and unfair.

Relocation Expense Adjustment

Q. Please provide an overview of the adjustment to relocation expense proposed by CCS witness Mr. Schultz.

A. Mr. Schultz contends that relocation expense included in the base year is unreasonable due to the changes in this cost from year to year. He proposes using a five-year average level of relocation expense.

Q. Does the Company accept this adjustment?

A. No. Consistent with the remaining O&M accounts, the Company has developed the December 2008 test year beginning with a Base Period and adjusting for known changes in the future, including an escalation to account for inflation. Proposing to average certain costs included within overall O&M accounts may be appropriate on occasion, but the Company is concerned that this introduces inconsistency and is frequently arbitrary in the treatment of different accounts.

Q. Is this adjustment consistent with other adjustments proposed by the CCS in this case?

A. In this single case witnesses for the CCS have proposed to average three different cost categories, all over different terms: overhaul expense over 4 years; insurance expense over 3 years; and relocation expense over 5 years. The Company does not believe it is appropriate to single out relocation expense as one of the costs to be adjusted to the lower of expected or average historical cost, and it is inconsistent with the uniform methodology used to prepare the Company's test year in this case.

Q. What is your recommendation on this adjustment?

A. The Commission should not adopt it.

MEHC Transition Consolidation and Reconfiguration

Q. Do you agree with DPU witness Mr. Croft's adjustment to remove certain costs identified as expenses related to the Mid-American Energy Holdings Company (MEHC) transaction?

A. No. These costs were erroneously recorded as MEHC Transaction costs. The costs are the result of Company initiatives to reduce lease expenses, and are part of the ongoing expenses of the Company. Numerous furniture reconfigurations and employee moves were conducted to relocate groups of employees and to vacate space no longer needed. In addition, these costs include costs associated with vacating leased premises. The reduction in employees that allowed for this project was a result of both the pre-MEHC Rebasing project and the reorganization by MEHC. These are not MEHC transition costs. Customers benefit from lower lease costs as a result of the office reconfigurations and consolidations.

Q. What is your recommendation on this adjustment?

A. The Commission should not adopt it.

Labor – Employee Complement

Q. Do you agree with Mr. Schultz that manpower is inflated in the case and adjustments should be made to reduce labor?

A. No. The Company has two problems with Mr. Schultz’s approach. First, the number of employees in the case should not be adjusted to any single point in time. Second, Mr. Schultz used the wrong number of employees to adjust the number included in the test year.

Q. What is the Company's position on adjusting the number of employees to a single point in time?

A. Vacancies vary over time and any one particular date chosen is not necessarily indicative of the sustainable future level of employees. Mr. Schultz states that because employee levels declined between July 2006 and June 2007 the case must have included excess employees. However, the case is not based solely on these two points in time, but on the entire period. There is a normal level of vacancies in the Company at any given time, and adjusting the average number of employees in the base period to the numbers at any one specific time misstates the anticipated costs during the test period. This concept is addressed further in Company witness Mr. Wilson's rebuttal testimony.

Q. Please describe the Company's disagreement with Mr. Schultz's adjustment, specifically the number of employees included in the test year.

A. Manpower is being held constant in the rate case, other than increases included in the incremental generation O&M adjustment offset by Automated Meter Reading savings.

The average number of employees included in the unadjusted base year is 5,704.5. However, on Page 4.11 of Exhibit RMP___(SRM-IS) the amounts paid to employees who subsequently left under the MEHC severance program are removed from results. Thus the adjusted base year results include a diminished employee count of 5,623.4, the 5,704.5 employees cited by Mr. Schultz less those leaving under the MEHC severance program whose pay is removed on Page 4.11. This is illustrated on Page 11.5.7 of my Exhibit RMP___(SRM-1R-RR).

Q. How does this impact the adjustment proposed by Mr. Schultz?

A. Mr. Schultz's adjustment is based on removing the pay applicable to the decline in employees between the filing and January 2008. The pay applicable to employees leaving under the MEHC severance program was already removed in the case. The corresponding reduction in headcount needs to be reflected in the number of employees deemed to be in the filing. The revised adjustment shown on Page 11.5.8 of Exhibit RMP___(SRM-1R-RR) uses Mr. Schultz's methods and numbers except for the number of employees in the test year. When corrected, this adjustment results in an increase in revenue requirement.

Q. Do you recommend making this adjustment?

A. No. The corrected adjustment goes in the Company's favor, but I am not recommending an adjustment. The case reflects the Company keeping manpower levels constant even in the face of inflation and increasing loads. However, if the Committee continues to recommend this adjustment, then revenue requirement should be increased appropriately.

Labor – Merit Increase

Q. Do you agree with DPU witness Garrett that the merit increase for exempt employees on December 26, 2006 should actually be a decrease?

A. Absolutely not. In order to produce his proposed adjustment, Mr. Garrett reviewed employee compensation both before and after the MEHC severance program took place. He then took the reduction in labor cost associated with the MEHC severance labor reductions and spread it across all labor classifications in the base year labor costs. He then compared his now adjusted labor costs from the first six months of the base year, the period before the non-union pay increase, to the adjusted labor costs in the second six months of the base year; the period after the non union pay increase was in effect. Using this approach, pay to the non-union categories appeared to decrease, while pay to union categories appeared to increase.

However, union employees did not qualify for the MEHC severance program, so applying any of it to their pay categories is erroneous. If we correctly attribute MEHC severance labor reductions to the non-union groups only, as was the actual case, it clearly shows that labor costs for exempt employees increased for the second six months of the base year. A comparison of Mr. Garrett's incorrect calculations with the appropriate reflection of the MEHC severance related labor reductions is shown in Page 11.5.9 of Exhibit RMP___(SRM-1-R-RR). Thus, Mr. Garrett's attempt to properly consider all aspects affecting pay besides merit increases by assigning exempt employees with a negative percentage is based on a faulty assumption regarding MEHC severance labor reductions. Giving other non-union employees no increase for the same faulty reason does not introduce more accuracy into the case but rather makes it less accurate. DPU's adjustment should therefore be rejected Another problem, as discussed in Mr. Wilson's testimony, is that there is a normal level of vacancies with predictable fluctuations through the year, along with other factors, which have not been considered by Mr. Garrett.

Q. Are there adjustments proposed to the Company's labor expenses that are being addressed by other Company witnesses?

A. Yes. Various adjustments were proposed to reduce future wage increases; incentive compensation; pension, medical and other employee benefits; and overtime pay. Adjustments were also proposed to reduce labor expenses by a productivity factor and modify the headcount included in the Company's case. Company witness Erich Wilson will explain why the Company disagrees with these proposed adjustments.

Cash Working Capital

Q. Please explain the nature of cash working capital.

A. Cash working capital is a rate base component that measures the amount of cash that a utility's investors are required to advance to fund the utility's day-to-day operations. The Company calculates cash working capital through a lead/lag study. A "lag," which creates a need for working capital, results from the fact that cash payments are generally received from customers after service has been provided. A "lead," which is a source of working capital, results when there is a delay between the recording of an expense and the actual cash payment of the expense. Cash working capital can be either positive or negative, depending upon whether the revenue lag exceeds the expense lead. The difference between the revenue lag and the expense lead is expressed in days. The number of days is then multiplied by the average daily operating expenses which quantifies the cash working capital required for, or available from, the utility operations. As shown in Exhibit RMP___(SRM-1S), Page 8.1, the December 2008 forecasted filing reflects a net revenue lag of 7.5 days (total Utah), resulting in a cash working capital requirement of $31.7 million on a Utah-allocated basis.

Exhibit RMP___(SRM-1S), Page 8.1

Rocky Mountain Power

Update Cash Working Capital

Twelve Months Ending Dec 31, 2008

Lead/Lag Study as of 3/03	Utah
Revenue Lag Days	44.82
Expense Lag Days	37.32
Net Lag Days	7.50
O&M Expense	1,491,123,600
Taxes Other Than Income	38,371,860
Federal Income Tax	10,180,152
State Income Tax	2,520,163
Total	1,542,195,775
Divided by Days in Year	365
Ave. Daily Cost of Service	4,225,194
Net Lag Days	7.50
Cash Working Capital	31,688,954

Q. Are you familiar with the adjustment to cash working capital being proposed by CCS witness Ms. DeRonne?

A. Yes. Ms. DeRonne recommends that a cash “lead” associated with the payment of interest on long term debt be included in the Company’s lead/lag study. This is based on the assumption that cash working capital generated by the interval between the time interest expense is incurred and the time it is actually paid should be attributed to utility customers.

Q. Does the lead-lag study utilized in this rate case include the component of payment of interest on long-term debt?

A. No.

Q. Do you agree that the cash "lead" associated with the payment of interest on long-term debt should be included in the Company's lead/lag study?

A. No. The idea of recognizing a cash "lead" for interest is a well-worn notion that is given little credence by recognized authorities in the field of utility accounting. For example, Robert L. Hahne addresses this issue in his book, <u>Accounting for Public Utilities</u>, which has become recognized as a standard accounting text for the utility industry. In his book, Mr. Hahne discusses a number of disfavored adjustments that have been proposed for determining cash working capital. He places at one extreme those who would recognize a lag in the receipt of operating income while ignoring delays in the disbursement of interest. At the other end of the spectrum he places those who would recognize that working capital exists in the delay in disbursements of interest without consideration of the lag in receipt of operating income. Mr. Hahne goes on to say that few commissions have accepted either of these points of view. Rather, he indicates that the most prevalent approach is to not consider the operating income component in the lead/lag study and to not recognize accruals of interest as a source of cash working capital. This is exactly the approach used by the Company in calculating the cash working capital reflected in this case – both the operating income lag and interest lead have been ignored.

Q Do you agree with the assertion made by Ms. DeRonne that the payment lead associated with the interest creates working capital collected from the Company's customers?

A. No. I would agree with the position taken by the Federal Energy Regulatory Commission (FERC) in its 1984 Notice of Proposed Rulemaking (NOPR) on "Calculation of Cash Working Capital Allowance for Electric Utilities."[1] In that NOPR, FERC declines to recognize a lag for return on investment (i.e., operating income) because its proposed rule does not require a utility to "utilize the interest component of return as working cash, even though the interest may not be paid to the bondholder until after the related revenue is received by the utility."

Q. Has the Utah Commission made previous rulings in the past regarding cash working capital?

A. Yes. In the Utah Commission Order in Docket No. 82-035-13, Page 27-30, the Commission states that the Division objected to including in the cash working capital calculation certain non-cash expenses, consisting primarily of depreciation expense, deferred taxes and cost of capital components, on the basis that they did not represent additional investment made by Company investors. The Utah Commission states, "We find that non-cash items should not be components of working capital because they do not represent additional uncompensated

[1] Calculation of Cash Working Capital Allowance for Electric Utilities, FERC Statutes and Regulations, Proposed Regulations 1982-1987 p.32,373 (1984).

investments."

This decision was reaffirmed in Mountain Fuel Docket No. 93-057-01 which states:

> In Docket No. 82-035-13 we adopted a method for determining cash working capital that excludes consideration of depreciation, interest expenses, and preferred and common dividends. That method has been reaffirmed in recent Commission orders and applies to PacifiCorp and U.S. West as well as to Mountain Fuel. If this method is to be changed, a strong burden of persuasion will first have to be met which must include a comprehensive analysis of all four of the above-mentioned items. Lacking such an analysis in this docket we reject the Committee's recommendation to include interest expenses and preferred dividends in the calculation of cash working capital.

The Utah Commission again rejected this concept in its order in the U.S. West general rate case, Docket No. 95-049-05, "[t]he Commission addressed and rejected the inclusion of interest, a component of net operating income, in the calculation of cash working capital in Docket No. 92-049-05" and then goes on to say "[t]he Commission again rejects the proposal to include interest in the calculation of cash working capital."

Other Commissions have also ruled on this issue. In Wyoming Docket No. 20000-ER-03-198, the Wyoming Commission stated in its Order:

> Both AARP and WIEC proposed that the study should recognize a cash "lead" in connection with the payment of preferred stock dividends and interest on long term debt. PacifiCorp opposed the adjustment, arguing inter alia, that these monies should not be recognized in a cash working capital calculation and that, if they were, there should be a corresponding adjustment for the lag involved in the receipt of operating income, noting that the common practice is to assume that these adjustments are offsetting and should be ignored for ratemaking purposes.

The Commission further stated:

> We reject the proposed adjustment. We consider the money received by a utility for preferred stock dividends and interest on long term debt to be the utility's money at that point rather than rate payer money which could be justified theoretically as useful in the calculation of cash working capital. Therefore, and without a corresponding operating income "lag" the proposed adjustment would distort the Company's cash working capital needs and should be denied.

Q. How would you recommend that the Commission respond to the cash working capital adjustment proposed by Ms. DeRonne?

A. I recommend that the Commission **once again** reject this adjustment. As explained above, recognition of the cash "lead" for long-term debt interest is one sided unless it is accompanied by recognition of a lag for operating income. The common practice is to assume that these two adjustments are offsetting and to ignore both in the working capital calculation. This is the approach used by the Company in this proceeding. It is entirely consistent with FERC pronouncements on cash working capital and follows the guidelines provided by recognized utility accounting reference works. It is also consistent with the long-standing position of this Commission as evidenced by the orders cited above.

Q Upon what year is the lead/lag study used in this rate case based?

A. Fiscal year 2003.

Q Does the Company believe that the lead/lag study is too outdated to use in this rate case?

A. No. The Company typically has prepared a lead/lag study every five years and this study is not an exception to this practice. The lead/lag study prepared prior to the fiscal year 2003 study was based on December 1998. The study prepared prior to that was based on 1991 data. The Company is in the process of preparing a lead/lag study based upon calendar year 2007 data which is consistent with the typical five year pattern.

Q **Does the Company ever update the current lead/lag study for changes in-between the typical five-year period?**

A. Yes. When appropriate, the Company updates the lead/lag study. The current fiscal year 2003 study was updated to include a change in income tax payments. When the study was prepared the Company was making monthly tax payments. Those payments were later changed to quarterly and, therefore, the Company adjusted the lag days to reflect the change. The driving factors that would result in an update to the lead/lag study would be changes in applicable business processes, such as billings, collections, accounts payable etc. The Company is not aware of any material process changes that should have been reflected in the current study other than the timing of the tax payments cited above.

Q. Has the Company ever used a lead/lag study in a general rate case that is older than 5 years?

A. Yes. The Company filed a general rate case in Docket No. 99-035-10 based on 1998 test period data using the Company's December 1991 lead lag study. The seven year old study used in the rate case was accepted by the Commission in determining the appropriate level of cash working capital to include as a rate base component.

Q. What is your conclusion regarding the cash working capital included in this case?

A. The cash working capital included in this case is appropriate. There have not been any significant changes in the underlying procedures since the last lead/lag study was completed other than the timing of the tax payments cited above.

Remove Regulatory Fees

Q. What adjustment did Mr. Ball propose to regulatory fees?

A. Mr. Ball contends that all costs associated with regulatory commission expense should be removed from rates. His position is based on his belief that ratepayers do not receive any benefit from regulatory proceedings, including FERC regulatory expenses. He supports this position by stating that since Utah Code 54-5-1.5(1)(a) imposes the cost of regulation upon the public utilities these costs should be paid by the Company shareholders and not the ratepayers.

Q. Does the Company agree with this position?

A. No. In my opinion, Mr. Ball's interpretation of the Utah Code is flawed. He is correct that the Utah Code requires public utilities to pay regulatory costs. However, he construes the reference to "the public utility" to mean "the shareholders." I believe this is an incorrect interpretation of the Utah Code. For example, even though the Company (public utility) is responsible for payment of income taxes, income taxes are included in the calculation of revenue requirement and customer rates. I do not believe the statute is intended to determine the ratemaking treatment of regulatory fees.

Q. Has the Commission allowed these costs in rates in the past?

A. Yes. The costs for both state and federal regulation are mandatory expenses of the Company imposed by jurisdictional regulations. They are a normal and essential cost of conducting business. The Commission has demonstrated acceptance of this fact by consistently allowing these costs in rates.

Adjust Allocation Factors

Q. What is your position on Mr. Brubaker's proposed adjustment to loads and the corresponding allocation factors?

A. Mr. Brubaker's proposed adjustment violates the matching principle and does not consider all revenue requirement components. Allocation factors used in this case are calculated based on the projected load in the December 31, 2008 test period. The same loads were used to calculate revenue and net power costs. It would be inappropriate and result in an invalid revenue requirement calculation to adjust factors without adjusting net power costs and the revenue forecast at the same time.

Summary

Q. What is your summary position on the rebuttal revenue requirement proposed by the Company?

A. The modified revenue requirement of $84.5 is the appropriate revenue requirement based on the revised test period used in this case. The Company has carefully reviewed the adjustments proposed by the parties and made adjustments which it believes are appropriate in this case.

Q. Does this conclude your testimony?

A. Yes.