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

A. My name is Steven R. McDougal and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah, 84111.

Q. Did you submit direct testimony, supplemental direct testimony, test period rebuttal testimony and second supplemental direct testimony in this proceeding?

A. Yes.

Purpose of Testimony

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

A. My Testimony will respond to the pre-filed direct testimony filed by the intervening parties regarding the Company's revenue requirement. My Testimony explains and supports the Company's revised overall revenue increase request of $57.4 million, reduced from the $116.1 million request included in the Company's second supplemental filing updated to use a December 31, 2009 test period. My testimony also provides:

- A detailed calculation of the $57.4 million requested revenue increase, including a summary of the differences between the $116.1 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 Utah Public Service Commission (“Commission”).

Q. Are any other witnesses presenting rebuttal testimony on behalf of Rocky Mountain Power?

A. Yes. The Company is presenting rebuttal testimony from four additional witnesses. Mr. A. Robert Lasich, President of PacifiCorp Energy, addresses certain wind-powered generation resource issues. Mr. Gregory N. Duvall, Director, Long Range Planning and Net Power Costs, addresses net power costs issues. Mr. Erich D. Wilson, Director, Human Resources, addresses labor related issues. Mr. Norman K. Ross, a director within the Company’s corporate tax department, addresses property tax issues.

Policy and Procedural Issues

Q. What policy and procedural issues are you addressing in your Testimony?

A. The Company has concerns with the following policy and procedural issues that I will address before describing the revised revenue requirement in this case. The issues discussed below are:

- Parties’ concerns regarding filing requirements in this docket expressed by the Committee of Consumer Services (“CCS”) and the Division of Public Utilities (“DPU”).
- The Company’s concerns regarding the completeness of non-Company filings in this case.
- The Company’s request to move to full deferred tax normalization.

Q. Should filing requirements be addressed in this docket?

A. The Company supports bringing more clarity to filing requirements. Senate Bill 75, which is currently before the Utah legislature, directs the Commission to establish rules concerning the minimum requirements within 180 days of the enactment of the 2009 legislation. The bill also provides remedies relating to the 240 day procedural schedule when a utility filing is deemed to be incomplete. A rule-making procedure as established by Senate Bill 75, rather than this docket, is the appropriate forum to address the issues raised in the testimony of the DPU and CCS. The Company believes this rule-making procedure should address the filing requirements of all parties, not just the requirements of the utility. The rule-making procedure should also create consistent time parameters that apply to all parties for updating major inputs into the revenue requirement based upon more current information.

Q. Does the Company have any concerns with the timing and completeness of the non-Company filings in this docket?

A. Yes. According to the Third Scheduling Order for Revenue Requirement and Cost of Service/Rate Design, dated November 6, 2008, in this case, non-Company revenue requirement direct testimony was due on February 12, 2009. The Company did not receive the DPU’s filing until after business hours on that date. Upon a quick review from the Company, the filing was found to be incomplete, with work papers that did not match the testimony and exhibits. Because the filing was made late on Thursday evening leading into Presidents' Day weekend, the Company lost several critical days of an already compressed schedule before these issues could be addressed with the DPU.

Q. What is the Company's position of moving deferred taxes to full normalization?

A. The Company's deferred income taxes in this case are calculated using 40 percent normalization of the book basis differences. The Company still believes that full normalization of deferred income taxes is the better approach and should be adopted by the Commission for future treatment of book basis differences in subsequent rate filings. The CCS mentions that this issue should be discussed as part of Docket No. 09-035-03. The Company finds this approach acceptable.

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), an overall price increase of $80.8 million is required to produce the 10.61 percent return on equity as stipulated in the cost of capital settlement filed with the Commission.

Q. Is the Company requesting the full $80.8 million required to earn a 10.6 percent return on equity?

A. No. The Company's request reflects 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 Testimony by $23.4 million to $57.4 million.

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

A. The Company's revised revenue increase of $57.4 million was calculated using the same allocation methodology and factors included in the second supplemental filing and incorporates certain adjustments proposed by other parties. In support of the revised calculation, Exhibit RMP___(SRM-1R) shows the revised revenue requirement requested by the Company. This Exhibit updates Tabs 1, 2, 9 and 10 in Exhibit RMP___(SRM-2SS) and adds a new Tab 11 containing backup pages for each new adjustment made to the Company's filing.

Revenue Requirement Adjustments

Q. Please identify the adjustments made to arrive at the revised overall revenue requirement.

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

		Capped Revenue Requirement
Supplemental Requested Revenue Increase		**$ 116,123,779**
	Capital Structure Settlement	$ (22,279,127)
	Lead Lag Days	(258,353)
11.1	Deferred Income Tax Correction	(17,747,988)
11.2	General Rate Case Advertising	(79,850)
11.3	Pension Curtailment Gain and Measurement Date Change	(3,532,840)
11.4	Automated Meter Reading Savings	(211,820)
11.5	Jim Bridger Mine Rate Base	(234,466)
11.6	Revised Plant Additions	(9,075,159)
11.7	Revised Plant Retirements	(1,602,409)
11.8	Revised Depreciation Expense	(3,267,829)
11.9	Revised Depreciation Reserve	1,891,812
11.10	Revised Deferred Income Taxes	2,644,274
11.11	Revised Adjustment to Budget	(1,269,915)
11.12	Net Power Cost Revisions	(2,504,617)
11.13	Green Tag Revenues	37,642
11.14	Renewable Energy Tax Credits	488,532
	MSP Price Cap Reduction	(1,728,636)
Rebuttal Requested Revenue Increase		**$ 57,393,030**

Capital Structure

Q. Please explain the change in cost of capital and capital structure.

A. The cost of capital and capital structure has been updated to the amounts in the table below, consistent with the capital structure stipulation.

	Capital Structure	Embedded Cost	Weighted Cost
Long-Term Debt	48.700%	6.020%	2.932%
Preferred Stock	0.300%	5.410%	0.016%
Common Stock	51.000%	10.608%	5.410%
	100.000%		8.358%

Lead Lag Days

Q. Please explain the adjustment you made to lead lag days.

A. This adjustment updates the Utah net lead lag days from 6.24 to 5.6 based on the DPU's review of invoices included in the lead lag study. This adjustment is described in more detail below, along with a discussion on why including interest expense in the lead lag study is inappropriate.

Deferred Income Tax Correction

Q. Please explain the adjustment you made to deferred income taxes in adjustment number 11.1 in your rebuttal Exhibit RMP___(SRM-1R).

A. In the current case the Company identified that, due to a processing discrepancy, the normalization percentages in the second supplemental filing utilized a 63 percent normalization level rather than a 100 percent normalization level for avoided cost and contributions in aid of construction. This issue was noted in the first supplemental response to DPU data request 58.11. This adjustment corrects the deferred income taxes in the case.

General Rate Case Advertising

Q. Please explain the adjustment you made to advertising in adjustment number 11.2 in your rebuttal Exhibit RMP___(SRM-1R).

A. On pages 10-12 of his direct testimony, Mr. David T. Thomson recommends reversing certain system allocated general rate case advertising expenses and assigning the costs directly to the state for which they were incurred. These expenses are for advertising needed to comply with requirements in each state to notify customers of general rate cases, public service announcements and legal notices.

Q. Does the Company agree that the advertising associated with general rate cases should be allocated on a situs basis?

A. Yes. The Company agrees that the general rate case advertising should be situs assigned to the jurisdiction for which the expense was incurred. This adjustment assigns $387 thousand using situs factors rather than the system allocation as included in the rate case.

Pension Curtailment Gain and Measurement Date Change

Q. Please describe adjustment 11.3 in your rebuttal Exhibit RMP___(SRM-1R) related to pension curtailment and measurement date change.

A. When the original case was filed, the Company had not received the order from the Commission allowing deferral and amortization of these expenses. On lines 347 – 349 of my second supplemental direct testimony I stated, “the pension and postretirement benefit expense in the filing reflects an ongoing normal level assuming no curtailment and measurement date change.” However, the 2009 budgeted O&M, to which the case was adjusted, assumed amortization of the curtailment gain over 10 years. This adjustment updates the case for the stipulation and order in the pension filing Docket No. 08-035-93. This adjustment is consistent with Ms. Donna Ramas' adjustments on a total Company basis. The total Company amount is allocated to Utah on an SO allocation factor.

Automated Meter Reading Savings

Q. Please explain the adjustment you made to the Utah Automated Meter Reading ("AMR") program in adjustment number 11.4 in your rebuttal Exhibit RMP___(SRM-1R).

A. This adjustment removes $220,464 related to the wage escalation on the employee reductions associated with the Utah AMR program.

Q. DPU witness Ms. Brenda Salter proposed a similar adjustment in her direct testimony in this proceeding. Does your calculation of the appropriate escalation amount differ from Ms. Salter's? Please explain.

A. Yes. In her direct testimony, Ms. Salter proposes to remove the escalation on the employee reduction associated with the AMR program. She states that her adjustment should be modified based on the determination of the appropriate labor escalation rate. The Company agrees that this is necessary. Ms. Salter's adjustment used DPU witness Mr. Mark E. Garrett's proposed labor escalation rate of 4.12 percent, removing $177,858 from meter reading expense. The Company's proposed adjustment has been calculated using the Company's labor escalation rate.

Jim Bridger Mine Rate Base

Q. Please explain CCS's proposed adjustment to the amount included in rate base for the Company's ownership interest in Jim Bridger Mine.

A. CCS's witness, Ms. Ramas proposes a three-part adjustment to the additions to Jim Bridger Mine plant balance. First, her adjustment aligns the balance for structures, equipment and mine development with the December 2008 actual level of $367.5 million as reported in the Company's response to DPU data request 47.2. Second, Ms. Ramas proposes to lower the Company's average December 2009 additions for structures, equipment and mine development to $9.637 million or 69 percent of the Company's forecast. Ms. Ramas testifies that, because the Company's December 2008 actual balance equals 69 percent of the Company's forecast balance, the Company's average 2009 forecast figure should also be scaled back by the same percentage. Lastly, Ms. Ramas reduces the materials and supplies balance for the Jim Bridger Mine. She argues that the balance of materials and supplies fluctuates and does not increase consistently from month to month, as reflected in the filing. Ms. Ramas proposes to use an average of June to December 2008 levels of materials and supplies as the balance to be included in rate base. Applying the seven month average reduces the materials and supplies 13-month average to $15.3m, or a decrease of $748 thousand.

Q. Please describe the adjustment made by the Company to the Jim Bridger Mine rate base?

A. The Company updated the filing for actual plant additions through December 31, 2008. The Company also adjusted the materials and supplies balance to reflect the seven month average as proposed by Ms. Ramas. Additionally, the Company has updated the forecast for Jim Bridger Mine plant in service during the test period. Overall, these adjustments reduce total Company rate base by approximately $4.7 million. Details of this calculation are provided in adjustment 11.5 of my Exhibit RMP___(SRM-1R).

Q. Does the Company's new forecast for Jim Bridger Mine plant balances for the 12 months ending December 31, 2009 reflect Ms. Ramas' proposed adjustment to reduce the Company's forecast?

A. No, the Company did not utilize Ms. Ramas' suggestions in preparing the 2009 plant in service forecast estimate. The Company disagrees with the CCS's revisions to the 2009 capital additions related to structures, equipment and mine development.

Q. Why does the Company disagree with Ms. Ramas' proposed adjustment for the Company's projected investment in the Jim Bridger Mine.

A. Ms. Ramas centers her argument around her assertion that the Company under-spent on capital during six months ended December 31, 2008. Therefore, she claims the forecasted balances must be overstated. She failed to consider that the plant in service as of December 31, 2008, is less than the amount originally included in the case because of a large year-end balance in construction work in progress ("CWIP"). During 2009, the Company plans to transfer approximately $10.1 million of the $10.4 million currently in CWIP into plant in service. When CWIP is considered, the Company was not significantly under budget with respect to capital spending for the additions to Bridger Coal Company's structures, equipment and mine development. The CCS omits the impending transfer of $10.1 million from CWIP to plant-in-service in 2009 in its analysis. Although the structures, equipment and mine development December 2008 balance was $9.6 million less than forecast, Bridger Coal Company's balance in CWIP was $10.4 million higher than forecasted. This represents a timing difference and does not justify disregarding the Company's forecast.

Q. Did the Company adjust the filing to account for these timing differences?

A. Yes. Because of this increase in the December 31, 2008 CWIP balance and the associated reduction in beginning plant in service, the Company has provided a new forecast for Bridger Coal Company's plant in service, which is included in adjustment 11.5 in Exhibit RMP___(SRM-1R). This adjustment reduces Jim Bridger Mine rate base by approximately $4.7 million on a total Company basis.

Revised Plant Additions

Q. Please explain adjustments 11.6 through 11.10 in your Exhibit RMP___(SRM-1R).

A. Adjustments 11.6 through 11.10 relate to changes in plant additions and retirements in response to various data requests and intervenor testimony, as described below. Adjustments 11.6 and 11.7 show the impact on plant in service related to changes in plant additions and retirements. Adjustments 11.8 through 11.10 show the impact on depreciation expense, depreciation reserve and deferred income taxes related to these changes.

The Company has used actual additions and retirements from July 2008 to December 2008, including the change in the balance in Federal Energy

Regulatory Commission ("FERC") account 106 (unclassified plant) in the capital addition adjustment. The Company has also updated the wind plant forecast amounts that were included in the case to those that were provided in data response DPU 61.10, which reflects Glenrock III and Rolling Hills going in service in January 2009. The Company has removed from the January 2009 to December 2009 forecast transmission and distribution projects identified in data response DPU 68.2 that were placed in service prior to December 31, 2008. In addition, the Company has increased the forecast for March 2009, April 2009, and May 2009 for specific Utah distribution and transmission projects. Lastly, the Company has removed from the case one cancelled and two delayed projects that were identified in data request CCS 27.61. The impact of these changes is shown in adjustment 11.6.

Q. Do you have any concerns with updating forecast capital additions from July 2008 through December 2008 with actual capital additions for that same time period?

A. Yes. The Company is continually analyzing the capital needs of the electrical system to determine which investments are required to maintain and provide a reliable service to its customers. It is not uncommon to change priorities in order to benefit the entire system. This may involve accelerating a project because of a critical need, which may cause a delay in other projects. Even though the timing and mix of plant additions may be different from what was included in the rate case, the Company expects that through December 2009 it will invest in total the amounts forecast in the rate case.

Q. Why did the Company agree to use actual additions and actual retirements from July 2008 through December 2008?

A. Overall, when comparing the additions contained in the rate case with actual additions through December 2008, the Company is behind on placing capital into service. The Company believes most of the additions in the case will be in service by the end of 2009. However, the Company does not have a revised schedule specifying when all of the additions will go in service during 2009.

Test period rate base is calculated by averaging the monthly plant balances from December 2008 to December 2009 to arrive at a 13 month average rate base. 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. Because of the test period rate base averaging methodology, even if the Company invests exactly what was forecast in the rate case, the filed test period rate base will be overstated. Since a revised schedule is not available for all of the amounts, the Company has included a conservative projection of rate base by removing the plant additions in question from the rate case.

Q. Why did the Company update the wind plant forecasts for the months January 2009 to April 2009?

A. The Company updated those amounts to reflect Rolling Hills and Glenrock III going in service in January 2009. This also reflects a more current forecast for the Glenrock, Seven Mile Hill and Seven Mile Hill II wind plants for the first four months of 2009, which was provided in data response DPU 61.10.

Q. Why did the Company remove from the January 2009 to December 2009 forecast amounts certain transmission and distribution projects that have been placed in service?

A. In his adjustment, Mr. Matthew Croft reduced the January 2009 to December 2009 forecast, using information received from data request DPU 68.2, for certain projects that were placed in service by December 2008. The Company agrees that the portions of transmission and distribution projects that were partially placed in service prior to December 31, 2008, will be included in the actual capital addition amounts in this rebuttal filing and should be removed from the revised January 2009 to December 2009 capital additions forecast.

Q. Please discuss the increase in the March 2009, April 2009, and May 2009 forecasts for specific distribution and transmission projects.

A. As described above, part of Mr. Croft's adjustment reviewed projects that were forecast in the case to go in service from January 2009 through December 2009 and removes amounts that had been placed in service before December 2008. As part of the Company review, the Company also looked at projects that were forecast to be in service by December 2008 that have not been placed in service by that date but will be placed in service during 2009. Four projects have been identified that fit into that category and the current forecast for those projects has been added into the Company's capital addition calculation. In addition, the Herriman project, placed in service in December 2008, has an additional amount that will be placed in service in May 2009. Furthermore, the amount in the case for the Gold Rush project, forecast to be in service in April 2009, has increased from the amount included in the case. The table below contains details of the changes to the capital addition calculation.

Project Name	**Technical Project Name**	**Function (Factor)**	**Month**	**Amount**
Gold Rush Distribution Project	Gold Rush 50 MW Load	Distribution (UT)	April 2009	2,230,560
Herriman Distribution Project	Herriman Purch Sub Prop & Trans ROW	Distribution (UT)	May 2009	1,335,000
Northeast Distribution Project	Northeast Instl 2nd 4-12kV Trnsf 4-12 kV	Distribution (UT)	May 2009	2,040,856
Copco II Sub Transmission Project	Copco II Sub Repl Exist 115-69	Transmission (SG)	March 2009	5,714,452
Eurus Transmission Project	Eurus 7 Mile Hills Intercon Miners Diff	Transmission (SG)	March 2009	7,016,802
Jim Bridger Transmission Project	Jim Bridger: Repl RAS A&B Scheme Project	Transmission (SG)	April 2009	5,920,341

Cancelled Projects

Q. Which of the projects identified as delayed or cancelled did you remove from the filing?

A. In response to data request CCS 27.61 the Company provided actual spending amounts for the projects included in the pro forma plant additions adjustment 8.10 in Exhibit RMP___(SRM-2SS). The Company identified three projects that have been cancelled or delayed beyond the test period. These projects include the Blundell No. 3 Generation Interconnection Project, the GSU Main Transformer Spare-ST Project, and the Yale Land Fund Project. These projects were removed by the parties because the in service dates have been cancelled or delayed beyond the end of the test period. The Company intends to redeploy this capital to other projects, but no definitive plans have been made thus these projects have been removed from the test period.

Q. Did the Company make any adjustments to green tag revenue and renewable energy tax credits to account for the delay in the in-service dates of the Rolling Hills and Glenrock III projects?

A. Yes. The impact of the delay is reflected in adjustment 11.13 and 11.14 in my rebuttal Exhibit.

Revised Adjustment to Budget

Q. Please explain the revised adjustment you made to reduce operation and maintenance costs, excluding net power costs ("O&M") included in the case to the 2009 budget levels in adjustment number 11.11 in your rebuttal Exhibit RMP___(SRM-1R).

A. This revision updated the original adjustment 4.23 in Exhibit RMP___(SRM-2SS) to reflect changes to O&M adjustments made in this filing. In addition, the following four corrections were made to this adjustment:

- As pointed out by Ms. Ramas in her testimony, by adjusting to the budget the Company is effectively adjusting to the budgeted overhauls rather than the four year average included in the generation overhaul adjustment 4.6 in Exhibit RMP___(SRM-2SS). The adjustment has been revised to remove the budgeted level of generation overhaul expenses and instead include the four year average consistent with the Company's generation overhaul adjustment.
- Consistent with the adjustment made above, the injuries and damages insurance expense included in the budget is replaced by the three year average computed in adjustment 4.17 in Exhibit RMP___(SRM-2SS).

- After reviewing budgeted advertising costs, the Company determined that some of the budgeted costs should be recorded below-the-line. This adjustment now correctly accounts for advertising costs that are appropriately included in the regulated results, as described below.
- In the second supplemental filing, the Supplemental Executive Retirement Plan ("SERP") expenses were inadvertently removed from the budget. This error has been corrected by including SERP costs in the Company's rebuttal revenue requirement consistent with the Commission's order in Docket No. 99-035-10.

Below I argue that the Commission should either reject or modify a number of intervenor proposed adjustments to the Company O&M projections. As discussed by DPU witness Mr. Thomas C. Brill, the sum of those proposed adjustments is less than the Company's original budget reconciliation adjustment 4.23. Other than the four adjustments discussed above and included in adjustment 11.11, most of the intervenor proposed O&M adjustments, even if adopted by the Commission, would not impact the final rate increase requested by the Company in this case.

Net Power Cost Revisions

Q. Please explain the adjustments 11.12 through 11.14 related to net power costs in Exhibit RMP___(SRM-1R).

A. As described in the testimony of Mr. Duvall, the Company is providing a revised net power cost study. Adjustment 11.12 adjusts net power costs included in the filing to the $1.048 billion amount included in Mr. Duvall's testimony.

Adjustments 11.13 and 11.14 update the green tag revenues and renewable energy tax credits to be consistent with the new net power costs included in this case.

Adjustments Rejected or Partially Accepted by the Company

Advertising Expense

Q. Please describe the adjustment proposed by the CCS regarding advertising expense?

A. CCS witness Ms. Ramas expresses concern regarding some of the advertising expenditures in the filing. However, she does not identify any specific dollar amounts to be adjusted in her testimony.

Q. What reason, if any, did Ms. Ramas provide as to why she did not propose a specific adjustment?

A. Ms. Ramas mentions several times in her testimony that the CCS has several data requests outstanding. She claims she was unable to quantify an adjustment because of the outstanding data requests.

Q. Were there any data requests regarding advertising expenses outstanding when Ms. Ramas filed her testimony?

A. No. The CCS submitted data request set 33 on January 27, 2009. Under the scheduling order in this case, the Company had until February 10, 2009 to respond to Ms. Ramas' request. The Company submitted the responses on February 10, 2009, in compliance with the scheduling order for discovery.

Q. Ms. Ramas mentions certain Company advertisements promoting the value of the Company's rates. Are you familiar with these advertisements?

A. Yes. These advertisements consist of comparisons of current electricity rates to rates charged to customers in 1985. Ms. Ramas included an example of this advertising campaign in Appendix 1 of her direct testimony.

Q. Are the costs associated with this advertising campaign included in rates?

A. No. The Company had no expense for this campaign during the 12 months ended June 2008. There are approximately $91 thousand on a total Company basis included in the Company's 2009 budget for these advertisements, but this expense is included as below the line advertising and is not included in this case.

Q. Have any revisions been made to advertising expenses as part of this filing?

A. Yes. The Company has conducted a thorough review of all advertisements planned for calendar year 2009. Adjustment 11.11 in my rebuttal Exhibit has been revised to adjust the amount of advertising included in the 2009 budget to more accurately reflect expenses that are properly included in customers rates.

Miscellaneous General Expense

Q. Please explain the DPU's proposed adjustment to miscellaneous general expense?

A. The adjustment proposed by DPU witness Ms. Salter removes three amounts from the normalized June 2008 results of operations, including:

- An adjustment to remove $184.7 thousand of legal consulting fees deemed to be out of period expenses;
- An adjustment to remove a legal consulting fee entry for $40.5 thousand deemed to belong below the line; and
- An adjustment to remove $64.9 thousand from legal consulting fees and

services due to the lack of supporting documentation from data request DPU 26.10.

The net of these adjustments proposed by the DPU removes $290 thousand from total Company results or $117 thousand on a Utah allocated basis.

Q. Does the Company agree with DPU's proposed adjustment to remove $184.7 thousand identified as out of period expenses?

A. No. The majority of the entries addressed in Ms. Salter's adjustment are legitimate costs that should remain in results of operations. Of the $184.7 thousand in legal consulting fees removed, $119.4 thousand represents costs that had been accrued and charged to expense in June 2008 as part of a larger entry totaling $938 thousand. This accrual was then reversed in July 2008, offsetting the expense during the base period. Therefore, this adjustment is removing a cost that is not in the case. It is also important to note that in the normal course of business, the Company will always have smaller invoices that will be overlooked in making the monthly accruals. These invoices will be paid in the following month. If adjustments are proposed, the DPU should consider adjustments both at the beginning and end of the base period.

Q. Does the Company agree with DPU's proposed adjustment to remove $40.5 thousand deemed to belong below the line from Results?

A. No. As specified in Ms. Salter's testimony, the Company response to data request DPU 26.10 explained that this expense represents nuclear development costs that are a below-the-line expense. These costs have already been excluded from this filing, and Ms. Salter's adjustment would effectively remove them a second time.

There are two parts to this entry. Part of these costs were reversed in September 2008, and moved below the line. The remainder was removed in adjustment 4.1 in Exhibit RMP___(SRM-2SS).

Q. Does the Company agree with DPU's proposed adjustment to remove $64.9 thousand from its revenue requirement in this case because of insufficient backup?

A. No. Ms. Salter states that the reason for disallowing this amount was due to missing documentation. The requested documentation has been found and is included as Exhibit RMP___(SRM-2R).

Labor

Q. Do you agree with the DPU adjustment to reduce incentive compensation to the budget levels on page 4.23.2?

A. No. Company adjustment 4.23 already reduces non-NPC O&M expense in the filing to the budget. Mr. Garrett's suggestion would essentially adjust this a second time.

Q. Are there any other statements you would like to make regarding the incentive compensation in the budget on Page 4.23.2?

A. Yes. PacifiCorp Energy incentive compensation was included with the regular pay on Page 4.23.2 instead of with the bonus/incentive. This results in the regular pay line being overstated and the incentive line understated by an identical amount. This was done to simplify the budgeting process at PacifiCorp Energy. Because adjustment 11.11 reduces the O&M at the total level in the budget to the amount included in this filing, this will not impact the filing.

Q. In his testimony on merit increases, Company witness Mr. Wilson stated that the case includes $193 million of non-union bare labor costs, which is less than the $201 million currently projected for the calendar year 2009. Please provide details on this calculation.

A. Exhibit RMP___(SRM-2SS) pages 4.11.3 and 4.11.4 contains the following information. This shows the amounts actually included in the rate case.

$ - thousands

Nonunion Bare Labor included in the case

	CY 2008	CY 2009
Officer/Exempt	168,726	174,632
PCCC Non-Exempt	7,670	7,670
Non-Exempt	9,984	10,333
	186,380	192,635

Data Requests DPU 48.4 and DPU 48.11 used by Mr. Garrett in his calculations give the following information. These amounts represent actual nonunion pay for the twelve months ending December 25, 2008, plus the annualized pay increases effective December 26, 2008.

$ - thousands

Nonunion Bare Labor from 12/26/2008 calculations

12/25/2008 Nonunion Pay	194,638
12/26/2008 Increase	6,073
12/26/2009 Nonunion Pay	200,711

As shown in the tables above, the projected 2009 wages included in the case of $193 million are less than using actual 2008 data escalated by the lower percent proposed by Mr. Garrett. This is partially due to adjustments such as the compliance adjustment included in the case. Therefore, as discussed in the testimony of Mr. Wilson, an adjustment to nonunion labor escalation is inappropriate.

O&M Escalation

Q. Please explain the DPU's proposed adjustment to the O&M escalation adjustment.

A. DPU witness Mr. Brill, on page 12 of his direct testimony, recommends rolling back the escalation factors used in calculating the calendar year 2009 test year non-power O&M costs to the escalation factors used in the July 17, 2008 filing. Mr. Brill proposes to use factors representing the first quarter 2008 as opposed to the escalation factors used in my Exhibit RMP___(SRM-2SS) which represent third quarter 2008 factors.

Q. Does the Company agree that the escalation factors used in Exhibit RMP___(SRM-2SS) should be updated to include the most up to date information available?

A. No. The Company is opposed to updating the escalation factors and especially by using outdated, prior period information that has no relationship to the base or forecasted periods. The Company believes that there needs to be a consistent methodology using the best information available at the time of filing.

Generation Overhaul Expense

Q. Please provide an explanation of the generation overhaul adjustments suggested by both the DPU and the CCS.

A. The adjustments proposed by both CCS witness Ms. Ramas and DPU witness Ms. Salter address the Commission's Order in Docket No. 07-035-93, issued August 11, 2008, which requires the Company to include overhaul expenses based on a four-year historical average level. In this regard, both adjustments remove the inflation escalation applied to the 4-year historical average as included in Exhibit RMP___(SRM-2SS) page 4.6. Both witnesses reduce generation overhaul expense to a total of $33.6 million and state that generation overhaul expenses through December 2009 should not be trued up to 2009 Company budget amounts.

Q. Does the Company agree with the adjustments proposed by the DPU and CCS?

A. Yes, in part. The Company adjusted the O&M budget adjustment 11.11 in Exhibit RMP___(SRM-1R) to the four year average overhaul amount, as described above, but continues to support the use of Global Insight indices to state overhauls in current dollars prior to calculating the four year average. I have already described earlier in my Testimony. Even though the Company recognizes the Commission's order to account for overhaul expenses at a historical 4-year average level, as articulated in my first supplemental testimony and illustrated in the example below, the Global Insight indices are not intended to address the year-to-year variances in expenses. Instead, such escalation is applied in an effort to address the time value of money and the issue of inflation, as the value of the dollar in the test period will be less than the value of the dollar in historical years. Company incurred expenses four years ago would cost more in test-year dollars to pay the same expense.

Q. Do you agree with Ms. Salter's statement that "inflationary pressures are already taken into account using the averaging methodology"? [1]

A. No. In fact, just the opposite is true. The purpose of averaging is to adjust for uneven costs, not to adjust for inflation. Historical amounts need to be restated to current dollars to adjust for inflationary pressures. A simple example below shows the impact of averaging on inflation, assuming a 2.5 percent inflation rate, a $100 amount in year one, and a four year average of years one through four used to project costs in year five. Using this assumption, example 1 shows the impact without adjusting for inflation, and example 2 shows the impact when years one through four are adjusted for inflation to current dollars. As shown in the example, with no escalation to account for inflation, a four year average of costs is $103.8, much less than the projected costs in year five, resulting in an expense level that is 2.5 years old compared to the current expenses. In example two, escalating for inflation, the average is equal to the year five amount resulting in an accurate forecast.

Example 1

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

Example 2

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

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[1] Direct testimony of Brenda Salter. DPU Exhibit 8.0. Lines 81-82

Injuries and Damages

Q. Please explain the DPU's proposed injuries and damages expense adjustment.

A. DPU witness Mr. Garrett, on pages 30 and 31 of his direct testimony, proposes to use a three-year cash basis average consistent with the Commission's decision in Docket No. 07-035-93. However, Mr. Garrett is proposing to change the accounting periods from which the three-year average is calculated from June 2006 through June 2008, to December 2006 through December 2008. Moving the three-year average to December 31, 2008, instead of June 30, 2008, increases revenue requirement by approximately $1.8 million on a total Company basis and $752 thousand on a Utah allocated basis.

Q. Is Mr. Garrett's proposed adjustment consistent with the base period and two prior historical years in this case?

A. No. The base period in this case is twelve months ended June 2008 with the two prior historical periods being twelve months ended June 2007 and June 2006.

Q. Does the Company agree with Mr. Garrett's proposed change to the three-year average periods?

A. No. Even though this proposed change increases revenue requirement, the Company is opposed to the notion of updating the base period from June 2008 to December 2008 to include the "latest information available" as Mr. Garrett states on page 31 of his direct testimony. This is a policy issue and involves more than just simply updating this single adjustment to reflect the latest information available. The Company believes that there needs to be a consistent methodology of either allowing updates or basing the rate case on the best information available at the time of filing. As noted here and set forth in Mr. Duvall's rebuttal testimony, the Company believes that the best information at the time of filing should be used unless there are compelling reasons for departure, which do not exist in this adjustment.

Q. What adjustment do you recommend for injuries and damages expense?

A. The proper method should utilize a three-year average of net cash payments using the base period twelve months ended June 2008 and the two prior historical periods of June 2007 and June 2006, consistent with the Commission's decision in Docket No. 07-035-93 and the second supplemental filing in this case.

Outside Services

Q. Please explain the DPU's proposed adjustment for outside services expense.

A. DPU witness Mr. Thomson, on pages 5-10 of his direct testimony, recommends reversing the system allocation of several outside services legal expenses and situs assigning those costs directly to the state for which they were incurred.

Q. How did Mr. Thomson identify these costs?

A. Mr. Thomson reviewed and sorted regulatory legal expenses from outside vendors, then separated them between Pacific Power and Rocky Mountain Power. He proposes assigning the Pacific Power expenses directly to the Pacific states and the Rocky Mountain Power expenses directly to Utah.

Q. Is this allocation of costs consistent with the approved Revised Protocol methodology?

A. No. The Revised Protocol allocates administrative and general costs with the factors set forth in appendix B of the Revised Protocol. The approved allocation factors for administrative and general expenses are system or situs.

Q. Do the legal expenses in Pacific Power pertain to just the Pacific Power states?

A. No. There are legal expenses for matters that relate to FERC, Bonneville Power Administration, and sale of utility property. It is an over simplification to assume that all of the costs charged to Pacific Power or Rocky Mountain Power pertain solely to the states served by those companies.

Q. Do you support assigning costs directly to the states if they can be readily identified?

A. I believe it is reasonable to assign costs directly to a jurisdiction as long as the costs are clearly related to a specific jurisdiction. The expenses identified by Mr. Thomson do not meet this criteria. For example, there are $84 thousand for FERC legal issues and over $258 thousand for BPA related legal work. These expenses apply to both business units and are not easily assignable to just one of them. Mr. Thomson makes no effort to exclude such system items from his adjustment.

Q. Should the Commission reject this adjustment by the DPU?

A. Yes. Since the Company doesn’t currently track these expenses at a level necessary to properly make this adjustment, I recommend this adjustment not be adopted in this proceeding. If the DPU would like to create separate divisional factors for costs, it would be appropriate to take this to the MSP Standing Committee for further consideration.

Chehalis Prepaid Maintenance Costs and Contractual Services Agreement ("CSA")

Q. Please provide a summary of the purchase price of the Chehalis plant.

A. The Company purchased the Chehalis generating plant on September 15, 2008. As a result of the acquisition, a total of $315.9 million was included in rate base in Exhibit RMP___(SRM-2SS). These costs are presented in summary below as well as in greater detail in data responses CCS 22.11 and DPU 56.3.

Net Generating Plant	$300.7m	Acct 102 - Electric Plant Purchased
Prepaid Maintenance	$ 13.7m	Acct 186 - Deferred Debits
Materials and Supplies	$ 1.5m	Acct 154 - Materials and Supplies
Total Plant in Service	**$315.9 million**	

Q. Please explain the DPU's proposed adjustments related to the Chehalis prepaid maintenance costs.

A. DPU Witness Mr. Croft, on page 8 and 9 of his direct testimony is proposing to remove the $4.7 million CSA adjustment from the Chehalis purchase price on the basis that "the Company has not demonstrated that these costs are not operation and maintenance expense related." Mr. Croft is also proposing to remove the $13.7 million related to the Chehalis prepaid maintenance costs from rate base. Mr. Croft further proposes to amortize the $4.7 million CSA adjustment and $10.2 million of the $13.7 million prepaid maintenance costs over a 20 year period.

Q. Please explain what the $4.7 million Chehalis CSA adjustment represents and why it is appropriate to include in the purchase price.

A. The $4.7 million CSA adjustment is simply part of the $315.9 million total purchase price of the Chehalis plant acquisition. Mr. Croft is under the mistaken impression that the $4.7 million are operation and maintenance expenses and should be expensed. This amount was identified in the purchase and sale agreement representing additional value owed the previous owner, Suez. The $4.7 million is included in the $300.7 million recorded to FERC account 102, electric plant purchased, in the summary above. The Company has not removed the CSA from rate base.

Q. Please explain what the $13.7 million Chehalis prepaid maintenance costs represent.

A. The prepaid maintenance costs of $13.7 million represent the variable fee payments that Suez made to the turbine manufacturer that were in excess of the value of work performed by the turbine manufacturer under the CSA at the time of closing. From the inception of the CSA until June 30, 2008, Suez made variable fee payments to the turbine manufacturer in the amount of $23.7 million. Since the variable fees are paid on a quarterly basis, the Company estimated an accrual of an additional $2.2 million of variable fees for July 1, 2008, through the September 15, 2008, close date. According to Suez, five combustion inspections had been performed by the turbine manufacturer prior to September 15, 2008. The Company estimated the value of the five combustion inspections to be $12.2 million. This results in $13.7 million remaining as prepaid maintenance costs acquired by the Company. The prepaid funds are recorded to FERC account 186 (miscellaneous deferred debits) until the planned overhauls occur.

Q. What are the obligations the turbine manufacturer is required to perform to receive payment of the funds?

A. The turbine manufacturer is required to inspect various physical equipment components to determine if they need repairs or replacements. The manufacturer is then required to repair or replace each of the components specified during that particular overhaul.

Q. How do customers benefit from the services performed during these planned overhauls?

A. Customers benefit because Suez paid the turbine manufacturer for capital repair work to be performed after the transaction closing, which is why the amounts were classified as prepaid maintenance. The manufacturer is responsible for cleaning, repairing, or replacing the equipment according to the turbine manufacturer's prescribed maintenance program. Customers also benefit because the turbine manufacturer assumes some financial risk associated with certain equipment failures and subsequent costs associated with component replacement. These costs would otherwise be borne by customers.

Q. Have any services related to the $13.7 million prepaid maintenance costs been performed? If so, have the associated prepaid amounts been moved from FERC account 186 (miscellaneous deferred debits) to FERC account 101 (electric plant in service)?

A. Yes. In October 2008, the turbine manufacturer performed a planned overhaul. At that time, the Company transferred and capitalized $9.5 million of the $13.7 million to FERC account 101 as part of plant in service. An additional $700 thousand of labor and overhead costs were capitalized to FERC account 101 for a total of $10.2 million. To reiterate, the overhaul work that was done qualified as maintenance that could be capitalized rather than expensed and none of the $10.2

million was charged to operation and maintenance expense. The remaining prepaid maintenance amount will reside in FERC account 186 until the next planned overhaul, scheduled to be performed in the spring of 2009.

Q. Pursuant to the October 2008 planned overhaul, how were the prepaid costs allocated to the physical assets?

A. The following is a listing of physical assets and their associated values that were included in the October 2008 maintenance overhaul:

Physical Asset Description and Quantity	**Transferred to Plant in Service (FERC Acct. 101)**
Combustion Liners assembly (qty 14)	$619,128
Cap assembly (qty 14)	$476,923
Transition Pieces (qty 14)	$850,323
Fuel Nozzle Assembly (qty 14)	$876,516
1st Stage Buckets / 7421	$2,123,929
2nd Stage Buckets	$1,344,602
1st Stage Nozzles	$1,091,217
2nd Stage Nozzles	$1,091,217
1st Stage Shroud	$476,640
2nd Stage Shroud	$331,772
Subtotal - per data response DPU 65.1	**$9,282,267**
Miscellaneous costs allocable to all items.	$237,686
Total transferred from pre-paid balance	**$9,519,953**
Labor to open up Unit 2 for Hot Gas Path (HGP) overhaul	$429,009
Capital Surcharge	$268,622
Total – per data response DPU 47.1	**$10,217,584**

Q. Does the Company have other similar turbine maintenance contracts? If so, what is the accounting treatment?

A. Yes. The Company has a similar turbine maintenance contract for the Lake Side generating plant. These prepaid maintenance costs are also included in FERC account 186 and allocated on the system generation "SG" allocation factor. When the necessary maintenance is performed under the contract, for the same reasons set forth above, the associated costs will be capitalized and transferred to FERC account 101.

Q. Do you agree with Mr. Croft's proposed adjustment?

A. No. These prepaid maintenance costs should be included as a rate base item since they are backed by actual physical assets, as evidenced in the table above. The Company's treatment of capitalizing, and not expensing, $10.2 million of maintenance costs is consistent with the Company's treatment of the Lake Side turbine maintenance contract.

Plant Additions

Q. Please describe the changes related to capital additions that were suggested by other parties but that were not made by the Company?

A. The Company has not removed the amount related to the Huntington Water Efficiency Management Project from the December 2009 forecast as suggested by Mr. Croft. The Company also did not remove the $12 million Goodnoe Hills amount as suggested by Mr. William A. Powell. Mr. Lasich addresses Goodnoe Hills in his rebuttal testimony.

Q. Why didn't the Company remove from the December 2009 forecast the amount that has been placed in service for the Huntington Water Efficiency Project through December 2008?

A. The Company does not agree that the amount for the Huntington Water Efficiency

Project should be removed from the December 2009 forecast as proposed by Mr. Croft. The portions of the Huntington Water Efficiency Project completed during 2008 were included in the rate case. As stated in DPU Data Request 48.35 and 59.6, this project has been separated into several phases because of the timing of the federal funding assistance that is subject to approval each year, with the final phase expected to be completed in June 2010. However, the Company has only included the capital cost for the phases of the project which were added into the Company's capital addition adjustment in July 2008 and August 2008. No amounts associated with the June 2010 phase are included in the rate case. Mr. Croft incorrectly removes from December 2009 amounts that are not included in the rate case during December 2009. The amounts included in the rate case correctly include the 2008 portions that have been added, and do not include any other amounts, therefore the portion the DPU is removing was not included in the case and their adjustment is inappropriate.

Distribution Plant

Q. Does the CCS make any other adjustments to the level of Utah distribution projects included in the Company's request?

A. Yes. Beyond updating the filing for actual data through December 2008, CCS witness Ms. Ramas notes that in the time period from July through December 2008, the actual spend was 28 percent lower than the original estimate included in the filing. Due to this observation, Ms. Ramas concludes that the Company's entire forecast for Utah distribution plant additions should be reduced to reflect an equivalent 28 percent decrease. Her calculation results in a forecasted total of

$145 million for Utah distribution plant through December 2009, considerably less than the Company's original projection of $202 million. This equates to a revenue requirement disallowance of $5.95 million including $1.06 million for the reduction in associated depreciation expense.

Q. What is the Company's position on the CCS distribution plant adjustment?

A. The Company has several issues with Ms. Ramas' adjustment. The Company believes that the overall level of Utah distribution plant additions for January through December 2009 will reflect the known downward forecast that is already included and not decrease beyond that level in 2009 for several reasons. First, the CCS incorrectly assumes that the Company did not account for the slowing economy when preparing the estimates in the case. To examine this correctly, it is necessary to separate the Utah distribution plant additions into two categories, on-going capital expenditures and major capital projects as shown in my rebuttal Exhibit RMP___(SRM-3R). In looking at the expenditures for ongoing capital programs, the Company spent $48.4 million in July 2008 through December 2008. This averages $8.1 million per month. The forecast included in Exhibit RMP___(SRM-2SS) for this time period was $64.9 million, or $10.8 million per month. For January 2009 through December 2009, the Company projects $54.7 million in expenditures for on-going capital programs. This averages only $4.6 million per month. When comparing the two, it becomes evident that the Company's forecast already includes a large reduction in anticipation of a slower economy. The CCS's extrapolation logic would reduce this even further to $3.3 million per month, almost one-third of the monthly levels actually experienced in

July through December 2008.

Second, the Company's forecasts for July through December 2008 were higher than actual largely due to delays in several major projects. The CCS incorrectly believes that the under-spending on these major projects in July through December 2008 is an indication that the Company will continue to under-spend through December 2009. Because some projects were moved from 2008 to 2009, the levels of spend in the 12 months ended December 2009 are likely to <u>increase</u> since the expenditures for the projects have been delayed into that time frame. For July 2008 through December 2009, the Company's projections included $82.9 million in capital additions for 19 major distribution projects in Utah. Although spending for these projects was delayed, they are still projected to be completed in 2009. Through January 2009, the Company has placed in service $19 million of these assets. Thus, the issue is simply a timing difference, and does not justify completely disregarding the Company's capital addition estimates.

Q. Has the Company accounted for timing differences in capital expenditures in your revised revenue requirement?

A. Yes. The capital additions in this case have been updated to reflect the effect the timing differences have on the 13-month average methodology used to calculate rate base in the filing. Please see adjustment 11.6 for details.

Materials and Supplies, Customer Advances for Construction, and Prepayments

Q. Please describe the DPU's adjustment to materials and supplies, customer advances for construction, and prepayments proposed by Mr. Garrett?

A. DPU witness Mr. Garrett proposes adjustments to the materials and supplies, customer advances for construction and prepayments accounts due to historical fluctuations and trends. Mr. Garrett suggests that in cases where accounts display either an increasing or decreasing trend ending balances should be included in rate base.[2] Furthermore, Mr. Garrett contends that, in situations where the historical data reflects fluctuations within the base year's monthly data, a 13-month average is appropriate. Because the mentioned accounts display investment level fluctuations after the end of the base year, Mr. Garrett contends that the December 2008 balances would be more representative of test year levels than the June 2008 balances used by the Company. The Company believes that the use of a consistent methodology simplifies the filing, and will over time be as accurate as Mr. Garrett's recommendation of using a different averaging methodology for each account. In accordance with Mr. Garrett's calculations, his proposed adjustments are as follows:

- Increase the materials and supplies year end balance to December 2008 levels due to the upward trend exhibited within calendar year 2008. The resulting adjustment is $4.9 million on a total Company basis and $1.9 million on a Utah allocated basis;
- As a result of his observation that the customer advances for construction account displayed an upward trend in ending balances from January 2006 to December 2008, he proposes an adjustment to reduce rate base by $1.5 million on a total Company basis and $777 thousand on a Utah allocated basis; and,

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[2] DPU Exhibit 5.0. Direct Testimony of Mark. E Garrett. P. 13, line 239.

- Due to fluctuations within monthly balances in calendar year 2008, the prepayments account should be presented at a 13-month average level. The averaging of this account in such a manner results in a total Company reduction to rate base of $1.5 million or $629 thousand Utah allocated.

Q. Does the Company agree with the DPU's adjustments to the materials and supplies and customer advances for construction accounts?

A. No. Even though the Company recognizes the upward trend noted by Mr. Garrett, the figures presented in our base period ending June of 2008 were the most representative of the materials and supplies and customer advances for construction balances for the test period used in this case. The Company does not typically apply inflation indices or forecast factors to miscellaneous rate base balances. In this regard, the Company assumes the balances at June 2008 levels will stay constant through the subsequent 12 months and thus provide an equal balance to averaging through December 2009. The balances as of June 2008 represent the most current historical data available at the time of filing, which would in effect, still capture the upward trend that Mr. Garrett discusses.

Q. Does the Company agree with DPU's adjustment to the prepayments account?

A. No. Prepayments are included at a prudent level when considering the overall historical trend in this account. Analysis of historical balances show that from December 2006 to June 2008 the prepayments balance experienced an average upward increase of 5 percent during each subsequent six month period. This would suggest that from June 2008 to December 2009 the balance in prepayments would either remain constant at June 2008 levels (as filed in the case) or moderately increase as previously displayed.

Rate Mitigation Cap

Q. Please explain the CCS's adjustment to the rate mitigation cap.

A. CCS witness Ms. Ramas adjusts the rate mitigation cap to 101.00 percent using her interpretation of the Utah revised protocol stipulation. Ms. Ramas maintains that the cap is dependent on the effective date of the order.

Q. Does the Company agree with the use of 101.00 percent for the rate mitigation cap

A. No. The averaging method I describe in my direct testimony using 101.25 percent for the first three months and 101.00 percent for the last nine months is the correct calculation of the rate mitigation cap.

Q. Is the CCS rate mitigation adjustment consistent with the test period in this case?

A. No. All other costs in the test period are based on the levels expected during calendar year 2009 and are not updated to the expected order date. For example, labor cost increases are not updated to the order date. Likewise, rate base additions occurring prior to the order date, and net power cost changes prior to the order date, are not annualized. It is not appropriate to update the rate mitigation cap to the expected order date without updating all parts of the rate case. The rate mitigation cap should be based on the test period, similar to all other expenses during the test period.

Fuel Stock

Q. Please summarize the adjustment that DPU witness Mr. Garrett recommends in regards to fuel stock.

A. In his direct testimony, Mr. Garrett recommends that the fuel stock level included in the Company's results be adjusted to reflect the 2008 levels using the 2009 average projected prices. This adjustment to fuel stock reduces Utah allocated rate base by approximately $16.9 million, resulting in a $2.1 million reduction to revenue requirement.

Q. What specifically are Mr. Garrett's issues with the 2009 levels of fuel stock projected by the Company?

A. Mr. Garrett claims the Company's projected 2009 inventory represents an average 79-day supply. Mr. Garrett considers this level too high citing that the comparable levels in 2008 and 2007 were 52 days and 42 days, respectively. Mr. Garrett highlights the fact that the Company not only owns a significant portion of the coal supply but also is located relatively closer to its coal sources than comparable utilities. Due to this, Mr. Garrett believes the Company should be subject to lower risk for potential interruptions or delays in delivery than other utilities. Economic justification, he claims, has not been provided by the Company supporting these elevated levels. Lastly, Mr. Garrett recommends using a 12-month average methodology to calculate fuel stock instead of the 13-month average currently used by the Company. He argues that this will normalize coal stockpiles levels that are subject to seasonal peaks.

Q. Does the Company agree with Mr. Garrett's arguments? Please explain.

No. First, Mr. Garrett states that 2009 average 79-day supply inventory is too high citing historic levels of 52 and 42 days in 2008 and 2007, respectively. Mr. Garrett's calculations are flawed. Mr. Garrett failed to include coal stockpiles at both the Company's Prep Plant and Deer Creek Mine in his analysis of 2007 and 2008. The Company, in response to DPU 61.2, provided historical stockpile levels for all the coal plants as well as the Deer Creek Mine and the Prep Plant for 2007 and 2008. Mr. Garrett excluded these balances in determining his average days of inventory in 2007 and 2008.

Q. What are the corrected average days of inventory?

The average days of coal stock for 2007 and 2008 are approximately 56 and 63 days, respectively.

Q. Do you agree with Mr. Garrett's calculation of 79-day supply for 2009?

A. No. Once again Mr. Garrett's calculation is flawed. While Mr. Garret did include the forecasted Prep Plant Stockpile balance for 2009, he failed to include the Deer Creek Mine stockpile balance and understated coal consumption to calculate his average day of supply. Mr. Garrett utilized only the Company's portion of Hunter Plant's consumption rather than total plant consumption in 2009; Mr. Garrett utilized the total Hunter Plant consumption in 2007 and 2008. The result is an overstatement of average-days of inventory for 2009.

Q. What is the correct average-days of inventory for 2009?

The average-days of coal for 2009 is approximately 76 days.

Q. How would these corrections change Mr. Garrett's proposed adjustment?

A. Currently, Mr. Garrett's proposed adjustment decreases Utah rate base by $16.9 million. Correcting his calculation changes his adjustment to a decrease in rate base of $8.4 million. However, the Company does not believe any adjustment is appropriate. Mr. Garrett's adjustment is premised on the assumption that at no time in 2007 or 2008 did the Company inventory levels come near the inventory level requested in the test year. If Mr. Garrett had included the Deer Creek and Prep Plant stockpiles in his 2007 and 2008 calculations and the correct consumed tonnage in 2009, he would have concluded the Company had over 74 days of inventory in November 2008 and averaged about 70 days of inventory during the last quarter of 2008.

Q. **Is it the Company's experience, as Mr. Garrett suggests, that is it typical to see lower inventory levels even in states located much greater distances from the coal production areas?**

A. Not necessarily. EVA (Energy Ventures Analysis) in its most recent 2009 COALCAST Stockpile Data Survey, reported coal stockpiles for utilities in the Western United States averaged 70 days for January. These levels are commensurate with the Company's stockpile levels at the beginning of the year.

Q. Which plant stockpiles have experienced increases?

A. As the Company stated in response to DPU 61.4, the Company has no rail facility at the majority of the Company plants and none in Utah. Approximately 88 percent of the overall increase in the Company's stockpile balance between January 2008 and December 2009 is associated with the Company's Utah plants.

Unlike Nevada Power or the other utilities Mr. Garrett alludes to, the Company does not have the ability to transport coal by rail. The Company cannot divert coal trains to other production basins during supply interruptions. Due to the Company's total reliance on local production for its Utah plants and the current supply/demand imbalance for Utah coal, the Company has prudently decided to carry higher inventory levels in Utah**.**

Q. Are the supply risks the same for surface and underground mines?

A. No. There is increased supply and quality risk associated with underground mining. All of the coal mines in Utah are underground mining operations.

Q. Can you discuss the coal supply situation in Utah?

A**.** Utah has a significant production shortfall. There are only six longwall mining operations in Utah and two have been curtailed. The Coop Mine is curtailed due to unexpected sandstone channels and Murray Energy's Westridge Mine continues to be curtailed due to geological movement, or "bounces." These bounces are generally associated with increasing depth of cover. Across the state, underground mining is challenged with maturing mining operations, increasing depth of cover, excess gases, narrowing seams, etc. Rigorous roof control plans will likely be required by the Mining Safety and Health Administration. These factors will likely contribute to increased supply interruptions.

Q Has the supply/demand imbalance impacted coal prices?

A. Yes. The FERC Energy Market Snapshot of Regional Coal Prices of February 6, 2009, provides a noteworthy comparison of coal prices across the country's major production basins. All of the production basins experienced significant increases in coal prices starting in early 2008. All of the production basins but one experienced substantial price decreases towards the end of 2008. However, Utah and Colorado are the exceptions. Utah and Colorado coal prices have continued to increase – from approximately $25/ton in the beginning of 2008 to over $70/ton in 2009. The high coal price is a result of an under supplied market. Due to supply shortfalls, some utilities have either implemented or are evaluating coal conservation measures as well as increasing stockpile levels on a long-term basis.

Q. Please summarize the Company's position regarding fuel stock.

A. The Commission should not accept Mr. Garrett's adjustment. The Company's strategic decision to increase stockpile levels ensures a secure supply of coal to the Company's generating plants and protects customers from supply interruptions.

Cash Working Capital ("CWC") and Lead Lag Study

Q. Please explain the purpose of a lead lag study.

A. The Company calculates CWC 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" is a source of working capital, which results when there is a delay between the recording of an expense and the actual cash payment of the expense. 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 CWC required for, or available from the utility operations.

Q. Has the Company completed a recent Lead Lag Study?

A. Yes. The Commission Order in Docket No. 07-035-93 stated on page 95 "[w]e agree with the Division and the Committee regarding the need to update the Company's cash working capital study for use in the Company's next general rate case." The Company complied with the Commission's order and completed a comprehensive lead lag study using December 31, 2007, data. The results of the December 2007 lead lag study were applied in this case in the calculation of the Company's revenue requirement filed as Exhibit RMP___(SRM-2SS). Page 8.1.1 of the Company's December 2009 forecasted filing reflects a net revenue lag of 6.24 days (total Utah), resulting in a CWC requirement of $21.7 million on a Utah allocated basis.

Q. Are you familiar with the adjustments to the December 2007 lead lag study being proposed by DPU witness Mr. Croft?

A. Yes. Mr. Croft recommends two adjustments to the lead lag calculation. First, Mr. Croft recommends revisions to the expense lag days resulting from an audit performed by the DPU of the Company's bank statements, a sample of coal, natural gas, purchased power and other invoices. The results of the audit determined that in certain instances the Company had paid the expense earlier than what the contract specifies. Secondly, Mr. Croft recommends the Company apply calendar year 2009 forecasted expenses and revenues to the DPU revised net revenue lag days.

Q. Mr. Croft's testimony proposes negative lead lag days for Utah of (3.73) after including long-term debt interest in the CWC calculation. Are there any formula errors in this calculation?

A. Yes. In DPU Exhibit 7.1 (confidential) the DPU inadvertently excluded interest on long-term debt from the Utah allocated expense total. In RMP data request 1.8, the DPU acknowledges that "it was not the Division's intent to exclude interest on long-term debt from the Utah allocated expense total." Updating this formula would change the DPU's net revenue lag days from a negative 3.73 days to a positive 0.43 days.

Q. How would you recommend that the Commission respond to the two adjustments proposed by Witness Croft?

A. I recommend, for purposes of this proceeding only, that the Commission accept the adjustment to reflect the revised expense lag days as proposed by Mr. Croft based on his audit of the Company's study. This change reduces the Company's net revenue lag days to 5.60 days. The revised lag of 5.60 days is included in my rebuttal revenue requirement results in this filing.

However, the Company asserts that it is not cost effective to calculate an expense lag by reviewing each and every invoice the Company paid during any specific period of time, due to the quantity of invoices received and processed by the Company each year. The Company prepared the calendar year 2007 lead lag study at a detailed level that was cost effective and produced an accurate result. The DPU conducted a detailed audit on a select few expense lag components and determined that the Company had, in a few instances, paid certain invoices on a different date than the invoice due date. The Company accepts the DPU's recommendation for this specific general rate case only, as the Company has not completed a comprehensive review of each of the invoices included in Mr. Croft's adjustment. The Company is confident that if a lead lag study were to be conducted where each and every revenue and expense item were reviewed on an individual basis the result would not differ materially from the Company's initial result.

Regarding Mr. Croft's second adjustment, I recommend that the Commission reject the adjustment to apply the forecasted calendar year 2009 revenues and expenses to the revised net revenue lag days. Mr. Croft does not provide any evidence as to why this should be done other than mentioning that it "should be applied to the study." Even though Mr. Croft proposes this new adjustment he did not prepare an exhibit to demonstrate the effect the adjustment would have on results. The Company proposes to keep the net lag days used in Company regulatory filings consistent with the current lead lag study. This is consistent with past Commission practice regarding the Company as well as other public utilities. Recalculating the net lag days for each filing based on current period results would likely be immaterial in nature, require another step in the process, and potentially cause confusion and additional audit steps for those reviewing the Company filings.

Q. Are you familiar with the adjustment to the lead lag study being proposed by DPU witness Mr. Garrett?

A. Yes. Mr. Garrett addresses an issue left open by the Commission for further discussion from Docket No. 07-035-93. In its final Order, the Commission did not adopt the CCS recommendation to include long-term debt interest expense in the lead lag study, but reaffirmed its earlier decision in Docket No. 93-057-01. However, the Commission stated it would be open to addressing the issue in the next general rate case but noted "[i]f 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." Mr. Garrett briefly addresses the four specific items outlined by the Commission in Docket No. 93-057-01, which are (1) depreciation, (2) interest expense, (3) preferred dividends, and (4) common dividends and how these pertain to the calculation of working capital, but Mr. Garrett did not include a comprehensive analysis of the four items.

Q. Why is it important to include a comprehensive analysis of all four of these items?

A. Together, these four items constitute what is known as "return on" and "return of" capital. Because these four items are integrally related, it is important to look at these four items together, not in the piecemeal manner done by Mr. Garrett where he attempts to look at each item individually without looking at the combined issues comprehensively.

Q. Did the Company prepare the December 2007 lead lag study consistent with the Commissions current cash working capital policy?

A. Yes. Consistent with the Commission's CWC policy,[3] the Company excluded depreciation expense, long-term debt interest expense, and dividends on both preferred and common stock from its December 2007 lead lag study. These four

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[3] UPSC Docket No. 07-035-93, Order issued August 11, 2008

components have never been authorized by the Commission for inclusion in the calculation of cash working capital.

Q. Do you agree with Mr. Garrett's recommendation to continue to exclude depreciation and common dividends from the lead lag study?

A. Yes.

Q. Do you agree with Mr. Garrett's recommendation to include long-term debt interest expense and preferred dividends in the lead lag study?

A. No. Mr. Garrett's main argument for including interest expense in the CWC calculation is that it is labeled as a "cash" item. The Company does not refute the idea that interest expense is a cash item, just like the Company's capital investments are cash items. However, neither one should be included in the CWC calculation. CWC is the amount of capital required by operations only and does not include amounts for non-operational items such as return on rate base. It should exclude the capital required to finance assets and non-cash expenses such as depreciation. Historically, regulators often calculated CWC using the 1/8 method of annual operating expenses. Consequently, CWC calculations were the direct result of operating activities only. Interest on bonds and preferred stock dividends are elements of the return component in the revenue requirement calculation, not part of the operating activities of the Company.

Because bonds, preferred stock, and common equity are used to finance the fixed assets of the utility, the related costs, including any lag in cash payments, are incorporated in the return on rate base. Intervenors may propose to include the lag on long term interest payments in the CWC calculation, but they often disregard the lag on short term interest payments. Short-term debt costs are recovered through Allowance for Funds Used During Construction ("AFUDC") on Construction Work in Progress ("CWIP"), and ultimately through depreciation expense over the life of the asset, after CWIP is transferred to rate base.

The same situation occurs relative to long-term debt cost recovery, which occurs through the return component in the revenue requirement. To separate out only long-term interest expense payment lag, and reduce rate base, will misstate the overall revenue requirement. Neither short-term nor long-term interest expense should impact operating capital. The Company's CWC calculation appropriately excludes both.

To reiterate what the Company expressed in testimony in Docket No. 07-035-93, 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. Robert L. Hahne addresses this issue in his book, Accounting for Public Utilities, which 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 (such as Mr. Garrett) 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 **not** to consider the operating income component in the lead/lag study and **not** to recognize accruals of interest as a source of cash working capital.[4] This is the approach used by the Company in the current case, and what has been approved by the Commission in prior cases.

Q. Do you have any other concerns with including interest expense in the lead lag study?

A. Yes. Mr. Garrett makes a simplifying assumption that all interest is collected from customers, and then paid after it is collected. In many cases, such as the Chehalis plant, acquired in September 2008, and the various wind projects added to plant in service in December 2008 and January 2009, interest expense is being incurred before being collected from customers. The Company began incurring interest charges when these plants went into service, prior to the inclusion of these costs in customer rates. Mr. Garrett makes no attempt to quantify the impact of this long-term lag in recovering this interest in his calculation. This would need to be part of any ”comprehensive analysis” of the four parts of return on and return of rate base as required by this Commission before making any changes to the calculation of case working capital.

Q. Does Mr. Garrett provide a “strong burden of persuasion” and a “comprehensive analysis” of all four components mentioned above as required in Docket No. 93-057-01?

A. No. Mr. Garrett states on page 5 of this testimony that his review is simply “a conceptual overview and discussion regarding the proper treatment within a lead-lag study.” Mr. Garrett uses the term “proper treatment” on page 5 of his direct testimony but does not provide any prescribed accounting regulations to backup

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[4] Accounting for Public Utilities, Robert L. Hahne et al, pages 5-22 and 5-23

his proper treatment. His testimony points out clearly that there is not one prescribed and accepted method for preparing a lead lag study. Mr. Garret uses the phrase on page 8 of his direct testimony that “interest expense is generally included,” while providing no backup. These statements fall short of the “strong burden of persuasion” and “comprehensive analysis” that the Commission stated it would require before considering a change to its long standing position.

Q. What is your recommendation to the Commission regarding the four specific items in question as to whether to include or exclude in a lead lag study?

A. I recommend the Commission continue its practice of excluding all four items, namely: (1) depreciation; (2) interest expense; (3) preferred dividends; and (4) common dividends, from the lead lag study used to calculate CWC. Including any of these four items in the lead lag study is inappropriate, and would be inconsistent with Commission practice.

I recommend that the Commission reject Mr. Garrett’s proposals on interest on long-term debt and preferred stock. As explained above, CWC is the amount of capital required by operations only and should not include non-cash items such as depreciation and non-operational items such as amounts related to financing long-term assets. Also, 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 recognize that these two items are offsetting and the proper treatment is to include or exclude both in the working capital calculation. This is the approach used by the Company in this proceeding.

Energy Trust of Oregon ("ETO") Funding

Q. How was ETO funding treated in this rebuttal filing?

A. ETO funding was treated consistently with the supplemental December 31, 2009, test period filing. The Incremental Generation O&M adjustment assumes Utah does not accept funding provided by ETO associated with the Goodnoe Hills wind plant in exchange for renewable energy credits being allocated to Oregon customers after the first five years of operation. The ETO funding is completely related to an O&M reimbursement, and does not impact plant in service. If Utah elects to accept ETO funding, as described by Mr. Mark Tallman in Docket No.07-035-93 and Mr. Lasich in this case, then approximately $2.6 million on a total company basis or $1.1 million on a Utah allocated basis could be deducted from the revenue requirement.

Computational Errors

Q. Did the Company find any computational errors in the intervening parties' adjustments which should be considered by the Commission if an adjustment is adopted?

A. Yes. The Company found errors in Mr. Garrett's materials and supplies, customer advances for construction, and prepayments adjustment (DPU Exhibits 5.3, 5.4, and 5.10); Mr. Croft's plant additions adjustment (DPU Exhibit 3.14); the modeling of Ms. Ramas' cancelled projects adjustment (CCS Exhibit 2.4) and Mr. Falkenberg's Rolling Hills adjustment. Correcting materials and supplies, customer advances for construction, and prepayments adjustment would result in an increase of $2.2 million, or $1.4 million Utah allocated, instead of $1.9

million, or $593.7 thousand Utah allocated as calculated by Mr. Garrett. The detailed computations of the correct calculation are presented in rebuttal Exhibit RMP___(SRM-4R), which corrects both computational errors and incorrect information included in a company data response. As stated above, the Company does not believe that an adjustment materials and supplies, customer advances for construction, and prepayments is necessary. Should the Commission find an adjustment necessary, the error should be corrected.

Next, Mr. Croft’s plant adjustment model contained a formula error that omitted $36.5 million in total Company plant additions from his calculation. Mr. Croft’s original adjustment reduced total Company rate base by $220 million. Correcting his error changes his adjustment to a $183.5 million reduction in rate base. In the Company’s plant addition rebuttal adjustment 11.6, this error was corrected.

Finally, in the CCS's Jurisdictional Allocation Model, the adjustment to accumulated depreciation included for the Rolling Hills and cancelled projects adjustments is made using the incorrect sign. The adjustments to accumulated depreciation would be a positive $4.1 million for Rolling Hills and $47 thousand for cancelled projects. The Company accepted the adjustment for cancelled projects in the plant addition rebuttal adjustment 11.6, and this error was corrected. The Company did not accept the Rolling Hills adjustment as proposed by Mr. Falkenberg; therefore, should the Commission decide to adopt this adjustment, the error should be corrected.

Summary

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

A. The modified revenue requirement of $57.4 million 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 either made adjustments that it believes are appropriate in this case or defended the proposals put forth by the Company.

Q. Does this conclude your testimony?

A. Yes.