Q. Please state your name and business address.

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

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

A. Yes.

Purpose of Testimony

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

A. The purpose of my revenue requirement rebuttal testimony is to provide a revised calculation of the Company's Utah-allocated revenue requirement in this case, including adjustments made to the original filing by the Company and also adjustments that address items raised in the direct testimony of intervening parties including the Division of Public Utilities ("DPU"), the Office of Consumer Services ("OCS"), Utah Association of Energy Users Intervention Group ("UAE") and the Utah Industrial Energy Consumers ("UIEC"). The revised revenue requirement incorporates adjustments addressed in my rebuttal testimony as well as the rebuttal testimony of other Company witnesses. I also respond to various issues raised in the direct revenue requirement testimony sponsored by the DPU, OCS, UAE and UIEC that the Company does not agree with and has not adopted in its revised revenue requirement. The Company believes these disputed adjustments should not be adopted by the Utah Public Service Commission in this case.

Revised Revenue Requirement

Q. Have you recalculated revenue requirement for the test year?

A. Yes. The Company has adopted a number of adjustments related to issues identified by the Company and intervening parties in this case, reducing the overall requested price change from $232.4 million to $188.1 million. The revised calculation is presented in exhibits accompanying my testimony. Exhibit RMP___(SRM-1R) shows a summary of the adjustments made to the revenue requirement originally requested by the Company. Exhibit RMP___(SRM-2R) is a revised Exhibit RMP__(SRM-3) from the Company's original filing with updated Tabs 1, 2, 9, 10, and 11 and includes a new Tab 12 containing supporting detail for each new adjustment made to the Company's filing.

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

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

Utah GRC Rebuttal - Company Position

Filed Results - Revised Protocol		**$**	**232,416,309**
Move to Rolled In			(15,013,228)
Adopt 2010 Protocol Agreement / State Income Taxes			(3,437,057)
Cost of Debt			(2,635,407)
12.1	SO2 Emission Allowances		102,511
12.2	REC Revenue		(18,516,752)
12.3	Joint Use Revenue		199,271
12.4	Outside Services and Miscellaneous Expense		(373,190)
12.5	Incremental O&M		(436,859)
12.6	Generation Overhaul		363,365
12.7	TRiP Labor Savings		(72,810)
12.8	Reduction to Salaries/Wages		(1,954,917)
12.9	Incentive Compensation		(1,134,813)
12.10	Pension and Post Retirement Benefits		(2,969,163)
12.11	Remove Challenge Grants		(208,064)
12.12	Incremental Bonus Depreciation Update		9,313,978
12.13	Pro Forma Plant Additions and Retirements		(6,168,127)
12.14	Misc Asset Removal		(497,667)
12.15	Bridger and Trapper Mines		37,044
12.16	Depreciation Expense Update		(866,989)
12.17	Depreciation Reserve Update		5,454,316
12.18	Plant Related Tax Update		(888,568)
12.19	Correct Deferred Tax Allocation Factors		(112,234)
12.20	Cottonwood Coal Lease		1,100,556
12.21	Powerdale Decommissioning		(369,612)
12.22	Net Power Costs		(5,274,617)
Rebuttal Results - 2010 Protocol		**$**	**188,057,278**

Inter-Jurisdictional Allocation

Q. The DPU, OCS, and UAE each proposed that Utah revenue requirement in this case be determined using the Rolled In allocation method. Do you agree?

A. The Company does not object to the proposal made by the DPU, OCS, and UAE.

However, since filing their direct testimonies, these parties have entered into an agreement with the Company regarding implementation of the 2010 Protocol that is pending Commission review and approval. The Company's rebuttal filing is prepared based on the 2010 Protocol agreement, which directs that the Hydro Endowment and Klamath Surcharge adjustments are deemed to net to zero and is the economic equivalent of Rolled In. Consequently, the results displayed on Tab 2 (2010 Protocol) and Tab 9 (Rolled In) of Exhibit RMP__(SRM-2R) are identical. As shown in the table of adjustments above, the originally filed revenue requirement is reduced approximately $15 million due to the change in allocation method. In addition, as part of the 2010 Protocol agreement the calculation of state income taxes under all allocation methods is changed to be based on the blended statutory tax rate rather than allocated on the Income Before Tax ("IBT") factor. This change reduces the filed revenue requirement by an additional $3.4 million; additional details are provided later in my testimony. The impact of each of the remaining adjustments comprising the Company's rebuttal revenue requirement is stated based on the 2010 Protocol allocation method, which as described above is the same as Rolled In.

Q. What is the status of the Company's application filed in Docket No. 02-035-04 to amend the Revised Protocol?

A. After filing this general rate case, the Company has continued to work with interested parties in hopes of reaching a settlement related to the 2010 Protocol. On June 27, 2011, the Company filed with the Commission an agreement reached between the Company and the DPU, OCS and UAE. The Commission had previously suspended the procedural schedule in that docket in order for parties to continue discussions. The agreement is now pending Commission review and approval.

Q. Is using the 2010 Protocol agreement to set rates in this case consistent with Commission orders in Docket No. 09-035-23?

A. Yes. In Docket No. 09-035-23 the Commission issued an order stating, "Although constrained by the time remaining in this docket, we intend to have inter-jurisdictional allocation issues addressed and the reasonableness of any allocation established prior to our approval of any future change in RMP's rates." Parties to the current rate case have provided substantial testimony supporting the use of a Rolled In allocation as a benchmark against which the reasonableness of any allocation method is to be established. Rolled In and 2010 Protocol produce identical results once the ECD adjustments are eliminated.

Q. In your direct testimony you pointed out that discussions were also occurring regarding the jurisdictional treatment of the Company's Class 1 demand side management ("DSM") programs. Is a change now required to the Company's filing in this case?

A. No. A consensus has not been reached among participants in those discussions, and in the absence of any agreement, the Company is not proposing to change the allocation treatment of Class 1 DSM programs in this case. The costs and benefits of these programs in this case remain situs assigned to the state in which the program originates.

Q. Please explain in more detail the change to the calculation of state income taxes.

A. In the Company's original filing state income taxes were allocated among all jurisdictions using IBT allocation factor as prescribed in the Revised Protocol allocation method. While this is conceptually consistent with the approved Revised Protocol and current practice under the Rolled In method, the resulting allocation of state income taxes to Utah may not yield intuitive results. When allocating income across multiple jurisdictions it is preferable to directly calculate income tax responsibility based on the income attributable to each jurisdiction and doing so avoids the anomalous results seen in this case as well as previous cases[1] in Utah.

Q. What do you mean that the results in this case are anomalous?

A. In the Company's revenue requirement model, the test period results feed into the calculation of the inter-jurisdictional allocation factors. Based on allocated taxable income in the originally filed case, Utah's Rolled In IBT factor is 58.96 percent (compared to an SG factor of 43.28 percent) and the resulting implied tax rate is 2.75 percent, well below the blended statutory rate of 4.54 percent. Because taxable income and the resulting state income taxes are negative, the lower than expected implied tax rate signifies Utah revenue requirement would be overstated unless the issue is corrected.

Q. What is the impact of the correction to the state income tax calculation?

A. If the correction is made once the change to Rolled In allocation is implemented,

[1] The Company has addressed the allocation of state income taxes in Docket Nos. 08-035-38, 10-035-13, and 10-035-89.

it reduces revenue requirement by approximately $3.4 million. The table below shows the detailed calculation of Utah-allocated taxable income the state income taxes expense before and after the correction is made.

Utah Allocated Income Tax Calculation - Rolled In Method

	As Filed	Corrected
	State Income Tax Allocated On IBT Factor	State Income Tax Allocated Calculated Using Statutory Rate
Calculation of Taxable Income:		
Operating Revenues	1,993,639,617	1,993,639,617
Operating Deductions:		
O & M Expenses	1,305,871,785	1,305,871,785
Depreciation Expense	233,031,726	233,031,726
Amortization Expense	20,477,315	20,477,315
Taxes Other Than Income	54,840,527	54,840,527
Interest & Dividends (AFUDC-Equity)	(17,946,961)	(17,946,961)
Misc Revenue & Expense	(2,527,310)	(2,527,310)
Total Operating Deductions	1,593,747,081	1,593,747,081
Other Deductions:		
Interest Deductions	152,738,934	152,738,029
Interest on PCRBS	-	-
Schedule M Adjustments	(429,766,212)	(429,766,212)
Income Before State Taxes	(182,612,610)	(182,611,705)
State Income Taxes	(5,368,321)	(8,635,365)
Total Taxable Income	(177,244,289)	(173,976,340)
Tax Rate	35.0%	35.0%
Federal Income Tax - Calculated	(62,035,501)	(60,891,719)
State Income Taxes		
Calculated	**(5,023,528)**	**(8,290,571)**
Production Tax Credits	(344,794)	(344,794)
Total State Tax Expense	(5,368,321)	(8,635,365)
Implied State Income Tax Rate	*2.75%*	*4.54%*

Q. Has the Company made similar adjustments in previous cases?

A. Yes. Most recently, in Docket No. 10-035-89 ("MPA II") the incremental revenue requirement of the MPA II projects was calculated using 4.54 percent of taxable income for the state income tax expense rather than relying on the IBT factor allocation.

Q. The state tax correction is one that affects multiple jurisdictions; has it been addressed in the Multi State Process arena?

A. Yes. The 2010 Protocol prescribes that state income taxes be computed using the weighted statutory rate calculation. The Company's original filing already included this calculation under the 2010 Protocol allocation methodology.

Q. Have any other issues related to inter-jurisdictional allocations been raised by parties in this proceeding?

A. Yes. UIEC witness Mr. Dennis E. Peseau proposes to depart from the accepted allocation of transmission plant in a thinly veiled attempt to disallow a portion of the Populus to Terminal transmission line. The Company does not agree with this treatment and has not adopted this adjustment. Mr. Peseau argues that the Company's investment in the Populus to Terminal line will only be able to operate for the benefit of retail customers at 50 percent of ultimate capacity and that the remaining portion should be 'allocated' away from retail customers during the Test Period. Company witness Mr. John Cupparo provides rebuttal testimony clearly demonstrating the prudence of the Populus to Terminal line, including the need for the investment and the benefits to the Company's retail customers. Mr. Cupparo's testimony renders Mr. Peseau's adjustment unnecessary and supports the allocation methodology currently accepted in Utah of allocating transmission plant to each the Company's retail jurisdictions, offset by a revenue credit for third party use that is similarly allocated across retail jurisdictions. Furthermore, inter-jurisdictional allocation of the Company's transmission facilities has been studied extensively by parties in Utah, Oregon, Wyoming, and Idaho, resulting in agreed upon allocation methodologies utilized in recent general rate cases in each of those states.

Q. Did Mr. Peseau misconstrue the inter-jurisdictional allocation of the Populus to Ben Lomond segment of this line in Docket No. 10-035-89?

A. Yes. On page 16 of his testimony, Mr. Peseau states, "As I understand it, the Company offered … to give Utah a transmission revenue credit of 20% of the bundled revenue associated with off-system sales of power." He also references the Company's response to UIEC data request 3.39 in the current docket as confirmation of his statement.

Mr. Peseau's interpretation of the issue is incorrect and his application of it in the revenue requirement phase of this case is inappropriate. Revenue requirement of the transmission assets in Docket 10-035-89 was computed in exactly the same manner as done in the current case, i.e. 100 percent of the project costs were allocated among the Company's six states while system-wide sales for resale is included as an offset to revenue requirement and is similarly allocated amongst all six jurisdictions. The response to UIEC 3.39 confirms that Mr. Peseau is confusing inter-jurisdictional cost allocation to the functionalization of sales for resale for purposes of class cost of service. UIEC 3.39 states,

> In Docket No. 10-035-89, the cost of service (COS) study showed a portion of Account 447 – Sales for Resale (approximately 20%) functionalized to Transmission. In the current proceeding, Exhibit RMP__(CCP-4) shows 0% of Account 447 functionalized to Transmission in order to be consistent with the Jurisdictional Allocation Model (JAM).

In DPU 47.10 the Company further clarified the response stating,

> In the class cost of service studies filed in Docket No. 10-035-89 Account 447 – Sales for Resale is functionalized 79.5355% to the Generation function and 20.4665% to the Transmission function. In the current case, this has been revised to 100% Generation and 0% Transmission, as explained in response to UIEC 3.39. In both cases, retail ratepayers were credited with the full amount of the wholesale sales revenues.

Q. Have other states served by PacifiCorp approved ratemaking treatment of Populus to Terminal as proposed by the Company in this case, including the inter-jurisdictional allocation?

A. Yes. The Wyoming Public Service Commission recently approved a stipulation resolving the Company's general rate case in Docket No. 20000-384-ER-10. The Populus to Terminal revenue requirement in that case was calculated identically to the Company's Utah filings, and the stipulation explicitly recognizes the appropriateness of including the Populus to Terminal investment in retail customers' rates.

Adjustments Adopted by the Company

Cost of Capital

Q. Does the Company's revised revenue requirement incorporate the cost of debt supported by Company witness Mr. Bruce N. Williams in his cost of capital rebuttal testimony?

A. Yes. As described by Mr. Williams, the Company has reduced the cost of debt in the Test Period from 5.81 percent to 5.71 percent, lowering revenue requirement by approximately $2.6 million.

Q. Did the Company alter its requested return on equity in this case?

A. No. As supported by the cost of capital rebuttal testimony of Company witness

Dr. Samuel C. Hadaway, the Company's revenue requirement continues to be calculated based on a 10.5 percent return on equity.

SO_2 Emission Allowance Revenue

Q. Please describe the adjustment to revenue from the sale of SO_2 emission allowances.

A. Adjustment 12.1 in Exhibit RMP___(SRM-2R) reduces the amortization of SO_2 emission allowance sales by $100,000 on a Utah allocated basis, pursuant to the settlement stipulation reached in Docket No. 10-035-12 ("MPA I") and approved by the Commission on June 15, 2010. In that settlement stipulation, parties agreed that the projected net revenue requirement impact of the projects included in MPA I included an annual credit of $200,000 (Utah-allocated) for incremental SO_2 emission allowance sales. In paragraph 11 of the stipulation the parties agreed that a pro rata share of this value (based on the length of time it was included as an offset to the regulatory asset accrual resulting from the settlement stipulation) will be excluded from the amount that would otherwise be used to establish the four-year amortization of SO_2 emission allowance sales revenue for general rate case purposes. The regulatory asset accrual established in the MPA I settlement was in place from July 1, 2010, through December 31, 2010; consequently, the Company may properly exclude $100,000 on a Utah-allocated basis from the amortization of SO_2 emission allowance sales in this case.

Q. Was this accounted for in the Company's direct filing in this case?

A. No. The Company inadvertently did not account for this settlement item in its direct filing.

Renewable Energy Credits

Q. Please explain the adjustment to revenue from the sale of renewable energy credits ("RECs").

A. As proposed in the direct testimony of Company witness Mr. Stefan Bird, the Company has updated the REC revenue forecast for the Test Period to incorporate successfully reaching a deal to sell additional RECs to NV Energy. The Company provided an updated REC revenue forecast in the first supplemental response to DPU data request 10.52. An even more recent forecast of known transactions was provided in response to UAE data request 11.1.[2] The total revenue and volume from known transactions in the Test Period is the same in both DPU 10.52 1st Supplemental and UAE 11.1, but there is a slight difference in the resource mix forecasted to be used to meet the contractual deliveries. The Company's rebuttal adjustment 12.2 in Exhibit RMP__(SRM-2R) incorporates the updated forecast of known REC sales transactions, provided in UAE 11.1. Assumptions regarding the remaining volume of RECs to be sold and the price realized for these additional forecasted sales remain unchanged from the Company's original filing. The Company's rebuttal adjustment is equal to the adjustment made by DPU witness Ms. Brenda Salter in her primary proposal regarding REC revenue, and it reduces revenue requirement in the rebuttal case by approximately $18.5 million compared to the Company's original filing. OCS witness Ms. Donna Ramas and UAE witness Mr. Kevin Higgins also incorporated the revised forecast from DPU 10.52 1st Supplemental into their proposed revenue requirement.

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[2] The 1st supplemental response to DPU 10.52 provided a full recalculation of the REC revenue adjustment based on the revised Test Period forecast while the response to UAE 11.1 only updated the known REC transactions.

Q. In addition to the known transactions, various intervening parties also proposed that the price assumed to be realized for RECs sold be increased substantially. Has the Company adopted this proposal?

A. No. The Company does not agree that the price assumed for REC transactions beyond those currently known should be increased in this case. Company witness Stefan Bird provides more details regarding REC sales transactions and the appropriate volumes and prices that should be included in the Test Period.

Q. Ms. Salter and Ms. Ramas also proposed mechanisms going forward to account for any differences between actual REC sales and the level included in customers' rates from this case. Is the Company opposed to such a mechanism?

A. No. The Company believes it is appropriate to track difference between the level of REC revenue in customer rates resulting from this case and actual REC revenue for later refund to or collection from customers. I will discuss this concept in more detail later in my testimony. I will also discuss the Company's position regarding REC revenue that has been deferred on the Company's books since February 22, 2010.

Joint Use Revenue

Q. Please explain the adjustment to joint use revenue.

A. Rebuttal Adjustment 12.3 in Exhibit RMP__(SRM-2R) simply reverses the original Adjustment 3.5, Joint Use Revenue, included in Exhibit RMP__(SRM-3) in the Company's original filing, consistent with the Commission's order on URTA Motion to Dismiss Pole Attachment Issues or for Alternative Relief issued in this docket on June 1, 2011. In my supplemental direct testimony on pole attachments filed June 8, 2011, I indicated the Company would withdraw Adjustment 3.5.

Outside Services and Miscellaneous Expense

Q. Do you agree with the removals of outside services and miscellaneous expenses recommended by Ms. Ramas in her testimony?

A. In part. Ms. Ramas proposes to remove nine items included in expenses for outside services and two items booked to miscellaneous expense. The Company agrees that all but two of these items should be removed from the Test Period. Adjustment 12.4 in Exhibit RMP__(SRM-2R) removes these seven items from outside services proposed in Ms. Ramas' adjustment that the Company agrees with. Both items that should not be removed are payments to Tegarden & Associates, Inc. in connection with appeals of property tax assessments in Idaho and Montana.

Q. Please explain why the payments to Tegarden & Associates, Inc. ("Tegarden") should not be removed from the Test Period.

A. Ms. Ramas first removes $44,562 related to charges from Tegarden because she claims it relates to out of period costs that were incurred prior to the base period in this case. The invoice for these charges was accrued in June 2009 to expense in Account 530007, Accounting/Audit/Technical Services. This accrual was reversed in July 2009, offsetting the expense charged when the payment was made. When the accrual and reversal are considered, this expense is never in the Test Period. Next, Ms. Ramas removes $54,929 related to additional charges from

Tegarden claiming the costs "are non-recurring in nature and associated with appraisal values as of 2006 and 2007" for Company property in Montana.

The Company is continually involved in litigated ad valorem proceedings, requiring valuation experts to support hearings to challenge the amount of property taxes paid by the Company. Perhaps more importantly the Company's challenges to property tax assessments influence the methodology for computing the property taxes owed now and in the future. Successful challenges to the methodologies used by various taxing jurisdictions carry over into future years and ultimately benefit all of the Company's customers by reducing subsequent property tax assessments. The assertion that these expenses are out of period and non-recurring is not correct.

Incremental Generation O&M

Q. Do you agree with the adjustment proposed by OCS witness Ms. Ramas to reduce incremental generation O&M?

A. Yes. Ms. Ramas proposes to reduce the Company's original adjustment for incremental generation O&M expense for two items based on the Company's response to OCS 15.6 and OCS 15.10. First, she removes a double count of actual operating costs related to the Dunlap I wind facility, reducing O&M by $178 thousand. Next, she reduces O&M for the Lake Side facility by $827 thousand because after the Company's case was prepared the long-term gas turbine parts and services contract with Siemens was renegotiated with a higher portion of the costs being capitalized. The Company has incorporated both of these items in its adjustment 12.5 in Exhibit RMP__(SRM-2R).

Generation Overhaul Expense

Q. Please describe the adjustment to generation overhaul expense.

A. Adjustment 12.6 in Exhibit RMP__(SRM-2R) to generation overhaul expense incorporates two changes from the Company's original filing. First, the Company is adopting the adjustment proposed by Dr. Artie Powell to use constant dollars in computing the four year average for generation overhauls. Second, the Company is incorporating the adjustment proposed by Ms. Ramas to update the spring 2011 Lake Side overhaul expense and the removal of the Little Mountain steam plant.

Q. Why is the Company adopting Dr. Powell's adjustment using constant dollars?

A. Dr. Powell correctly points out that from an economic standpoint, averaging dollars from multiple years requires the dollars to be stated on a consistent basis prior to averaging. The Company agrees with his statement that: "economic theory suggests that in order to compare two values separated by time, the values need to have a common monetary base: the values should be expressed in real terms."[3]

Q. Can you provide a simple example to further support the concept of using constant dollars when computing an average expense over time?

A. Yes. As I mentioned in my direct testimony on revenue requirement, the purpose of averaging is to adjust for uneven costs, not to adjust for inflation. A simple example below shows the impact of averaging, assuming a 2.5 percent inflation rate, a $100 amount in year one, and a four year average of years one through four used to project costs in year five. Using this assumption, Example 1 shows the

[3] Direct testimony of Dr. Artie Powell, page 28, lines 475 – 477.

impact without adjusting for inflation, and Example 2 shows the impact when years one through four are stated in real dollars.

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

Example 1

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

Avg. $103.8

Example 2

Year		Amount	Escalation		Adjusted Amount
1	$	100.0	1.104	$	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			

Avg. $110.4

Q. Please describe the adjustment adopted with regards to the spring 2011 Lake Side overhaul and for the removal of the Little Mountain steam plant.

A. As proposed by Ms. Ramas the spring 2011 Lake Side overhaul was updated to reflect the actual overhaul expense incurred, and the Little Mountain steam plant overhaul expense was removed because the Little Mountain steam plant is expected to be retired in February 2012.

TRiP Labor Savings

Q. Please briefly describe OCS Witness Ms. Ramas' TRiP Energy Trading computer system labor cost savings adjustment.

A. Ms. Ramas proposes to include some labor savings into the case associated with the implementation of the commercial and trading TRiP Energy Trading System which was placed into service February 1, 2011. The Company's cost benefit analysis mentioned projected reductions in full-time equivalent ("FTE") employee positions that will result from implementation of the project. Exhibit OCS 3.16 reduces labor expense for six full-time equivalents and includes labor savings of $900,000 (6 FTE's times $150,000 each) based on high-level estimates used in the initial analysis of the project.

Q. Does the Company agree that an adjustment to labor expense is needed as a result of the TRiP implementation?

A. Yes. The Company agrees that an adjustment is needed to reflect labor savings in the Test Period resulting from implementation of the TRiP system, but the required adjustment is smaller than the adjustment proposed by Ms. Ramas. There has been a reduction in employees as a result of the implementation of the TRiP system; however, only some of the positions that were eliminated were still on the payroll during the base period. The Company has calculated the labor expenses that need to be removed from this case by looking at the specific jobs eliminated, and the number of months an employee was working in the position during the base period. Specifically, three positions in the information technology department were eliminated in 2007, one position in the finance department was eliminated in 2008, and two positions in the commercial and trading department were eliminated in 2010. Based on this calculation, costs for 1.67 FTEs that were eliminated by the TRiP system are included in the base period in this case and should be removed. The remaining positions were eliminated prior to the base period. Each of the reductions occurred well ahead of the targeted labor savings timeline of six months after the implementation of the new system. Adjustment 12.7 in Exhibit RMP__(SRM-2R) reduces revenue requirement by approximately $173 thousand on a total Company basis or $73 thousand on a Utah allocated basis.

Reduction to Salaries

Q. Please briefly describe OCS Witness Ramas' reduction to salaries and wage adjustment.

A. Ms. Ramas proposes to reduce Test Period salaries and wage expense by 1.27 percent which represents the three year comparison of actual and projected regular, overtime, and premium pay from the last three rate cases. Exhibit OCS 3.15 reduces labor expense by approximately $6.3 million on a total Company basis. Ms. Ramas' adjustment reduces revenue requirement by approximately $1.9 million on a Utah allocated basis.

Q. Is the Company accepting Ms. Ramas' adjustment in this case?

A. Yes. Although the Company does not conceptually agree with the adjustment, the Company has adopted it for this case in Adjustment 12.8 of Exhibit RMP___(SRM-2R). Please refer to the rebuttal testimony of Company witness Mr. Erich D. Wilson as he describes the Company's position on Ms. Ramas' salaries and wages expense adjustment and why the Company accepts her adjustment.

Q. Will the Company be making this adjustment in future cases?

A. No. The Company believes that the best method for calculating salary and wage expense is using actual wages in the base period and then escalating those wages with known union contract increases or target increases when known contract information is not available.

Incentive Compensation

Q. What level of incentive compensation did the Company include in this case?

A. In its original filing, the Company included annual incentive plan compensation costs of approximately $33.7 million which is the average of the target payout levels expected in 2011 and 2012.

Q. Did the OCS and DPU propose alternative adjustments for incentive compensation in this case?

A. Yes.

Q. Please briefly describe OCS witness Ms. Ramas' adjustment to incentive compensation.

A. Ms. Ramas proposes to adjust incentive compensation to a two year average of 2009 and 2010 actual payout escalated for the January 2011 non-union labor increase and 50 percent of the January 2012 non-union labor increase. Her adjustment in Exhibit OCS 3.17 reduces incentive expense included in the case to $29.5 million or a reduction of approximately $1.2 million on a Utah allocated basis. Please refer to the rebuttal testimony of Company witness Mr. Wilson as he describes the Company's position on Ms. Ramas' incentive compensation adjustment.

Q. Please briefly describe DPU witness Mr. Mark E. Garrett adjustment to incentive compensation.

A. Mr. Garrett proposes to adjust incentive compensation to the three year average of

2008, 2009, and 2010 actual payout. His adjustment in Exhibit DPU 10.3 reduces incentive expense included in the case to approximately $28.8 million or a reduction of approximately $1.4 million on a Utah allocated basis. Please refer to the rebuttal testimony of Company witness Mr. Wilson as he describes the Company's position on Mr. Garrett's incentive compensation adjustment.

Q. What adjustment does the Company propose to the level of incentive compensation?

A. In this case, the Company accepts an averaging of incentive compensation expense. The concept of averaging of certain expenses that tend to fluctuate from year to year is an acceptable approach in rate making in certain situations. While the OCS approach of using only two data points (2009 and 2010) is insufficient for a proper average, the Company supports a three year historical average calculated by comparing the actual "at-risk" incentive compensation payout as compared to payroll (regular time, overtime, and premium pay) for years 2008 through 2010, multiplied by Test Period wages. The "at-risk" incentive payout percentage of payroll is calculated in this case to be 14.90 percent as shown in the following table.

Year	**Payroll**	**Incentive**	**Paid "At-Risk" percent**
2008	$190,502,520	$31,142,229	16.35%
2009	200,112,042	29,876,294	14.93%
2010	197,330,060	26,606,117	13.48%
Total	$587,944,622	$87,624,640	14.90%

Using this approach results in a test year incentive expense of approximately $30.1 million and is included in Adjustment 12.9 in Exhibit

RMP___(SRM-2R). The Company's proposal reduces revenue requirement by approximately $2.7 million on a total Company basis or approximately $1.1 million on a Utah allocated basis. The Company's adjustment is similar in concept to both Ms. Ramas and Mr. Garrett in that it allows for an averaging. The Company believes a three year average is more appropriate and is consistent with other averages used in the Test Period for items such as insurance expense. The Company's approach differs from Ms. Ramas and Mr. Garrett adjustment in that it applies the average payout rate to the adjusted wages in the Test Period.

Pension Expense

Q. What level of pension expense did the Company include in this case?

A. In its original filing, the Company included pension expense of $27.8 million for the PacifiCorp retirement plan and $13.85 million for the Local 57 contribution amount for a total pension expense of approximately $41.65 million which is the average of the Company's actuarial projections for 2011 and 2012. These were the most current figures available at the time of filing.

Q. Did the OCS propose alternative adjustments for pension expense in this case?

A. Yes. Ms. Ramas proposes to adjust the PacifiCorp retirement plan expense for 2011 to the actual amount of $ 24.0 million and then further adjusting this amount downward to $21.5 million by increasing the long-term rate of return assumption by 25 basis points. Ms. Ramas also proposes to adjust the Local 57 contribution by annualizing the January to June 2011 actual amount of $6.4 million to $12.8 million for the Test Period. Please refer to the rebuttal testimony of Company witness Mr. Williams as he describes the Company's position on Ms. Ramas' pension expense adjustment.

Q. What adjustment does the Company propose to the level of pension expense?

A. The Company proposes to update the pension expense and post retirement benefit expense to reflect the average of calendar year 2011 actual expense and updated calendar year 2012 projections. The Company proposes a further adjustment to Local 57 retirement expense to reflect updated expected expense during the Test Period equal to cash contributions ($18.5 million) less amount to be reimbursed by the union beginning in 2015 ($5.9 million). These changes result in a Test Period pension expense of $33.9 million and post retirement benefit expense of $16.95 million and are included in Adjustment 12.10 in Exhibit RMP___(SRM-2R). The Company's proposal reduces revenue requirement by approximately $3.0 million on a Utah allocated basis. Adjustment 12.10 in Exhibit RMP___(SRM-2R) is consistent with the testimony of Mr. Williams.

Challenge Grants & Rent Subsidy

Q. Please describe the adjustments proposed by OCS witness Ms. Ramas and DPU witness Ms. Salter with regards to challenge grants.

A. The Company sub-lets office space in the One Utah Center to Economic Development Corporation of Utah ("EDCU") and the Utah Sports Commission for $1 per month rent plus operating expenses. The resulting subsidy is booked as a challenge grant to these organizations amounting to approximately $163 thousand in the Test Period (including escalation). Both Ms. Ramas and Ms. Salter propose disallowing rent contributions made by the Company to the EDCU and the Utah Sports Commission. Ms. Salter also recommends disallowance of $42 thousand for other challenge grants in the base period.

Q. Does the Company agree to incorporate the adjustments as proposed by Ms. Ramas and Ms. Salter?

A. Yes. The Company has included an adjustment to remove the rent contribution and challenge grants from the filing as shown on page 12.11 of Exhibit RMP__(SRM-2R). This reduces the Company's revenue requirement by approximately $208,000.

Incremental Bonus Depreciation Update

Q. Please explain the concept of bonus depreciation as it relates to this case.

A. Bonus depreciation refers to a first-year tax depreciation allowance for qualified property. The adjusted basis of the property is reduced by the bonus depreciation before computing the amount otherwise allowable as a tax depreciation deduction for the tax year and any later tax year. Pursuant to the Tax Relief, Unemployment Insurance Reauthorization, Job Creation Act ("the Act"), which was signed into law on December 17, 2010, 50 percent bonus depreciation was extended through 2012 on qualifying property, and qualified property acquired and placed in service after September 8, 2010, and before January 1, 2012, became eligible for 100 percent first-year bonus depreciation. Bonus depreciation does not impact the total level of income tax expense in the test year, but it does give rise to additional accumulated deferred income taxes which are included as a reduction to rate base.

The Company's direct filing in this case reflected the Company's interpretation of the Act just after it was signed into law. Based on this preliminary analysis of the Act, the vast majority of property included in this case placed into service after September 8, 2010, and before January 1, 2012, was assumed to be eligible for 100 percent first-year bonus depreciation. Property forecast to be placed into service between January 1, 2012, and June 30, 2012, was assumed to be eligible for 50 percent first-year bonus depreciation.

Q. If the impact of bonus depreciation was already included in the Company's filing why is an additional adjustment required now?

A. OCS witness Ms. Ramas and DPU witness Mr. Matthew Croft both correctly point out that an adjustment is required to correct the impact of bonus depreciation due to guidance received from the Internal Revenue Service ("IRS") regarding the applicability of the Act to assets included in this case.

Q. Will you further explain the IRS guidance and how it would change the Company's filing?

A. Yes. On March 29, 2011, the IRS issued guidance in Revenue Procedure 2011-26, which clarified that under the Act, self-constructed property is acquired when manufacture, construction, or production of the property begins. This date may be determined by identifying when physical work of a significant nature begins under a facts-and-circumstances analysis or under a 10 percent safe harbor. Post rate case filing and utilization of this guidance requires that the acquisition date of certain self-constructed property, such as the Populus to Ben Lomond transmission line, which was placed in service in November 2010, be considered as having occurred prior to September 8, 2010. Accordingly this project only qualifies for 50 percent bonus depreciation not 100 percent bonus depreciation as assumed in the Company's original filing.

Accordingly, the Company has recomputed the impact of the Act in this case consistent with the IRS guidance. I have provided the necessary adjustment and corrected the revenue requirement. The Company provided this adjustment in its response to OCS data request 27.2 on May 18, 2011, to provide parties the opportunity to review the impact of the IRS guidance. Revenue requirement in this case is increased by approximately $9.3 million when bonus depreciation is properly reflected.

Q. Ms. Ramas also makes reference to an application filed by the OCS (Docket No. 11-035-47) requesting deferred accounting treatment of bonus depreciation as it relates to previous Utah dockets. Does your rebuttal adjustment address that application or any previous Utah dockets?

A. No. The adjustment made in the Company's rebuttal filing is specific to this case and does not address the application filed by the OCS. The implications of the Act on previous cases will be considered in Docket No. 11-035-47.

Pro Forma Plant Additions and Retirements

Q. Various witnesses for intervening parties have proposed adjustments to capital additions. Does the Company agree with these proposed adjustments?

A. Mr. Croft of the DPU, Ms. Ramas of the OCS, and Mr. Jim T. Selecky of UIEC have all proposed adjustments to the Company's capital additions. The Company is accepting in principle adjustments to capital additions, plant retirements, depreciation expense, and depreciation reserve which result from using actual capital additions and retirements for July 2010 to March 2011 and updating April

2011 to June 2012 capital additions as proposed by DPU witness Mr. Croft. The Company is not adopting Mr. Croft's adjustment to update composite depreciation rates and recalculate retirement rates included in the filing. The Company is accepting Ms. Ramas' adjustment to replace July 2010 to March 2011 forecast capital and retirements with actuals for that same time period, but rejecting Ms. Ramas' adjustment to reduce April 2011 to June 2012 forecasted capital additions by 4.34 percent. The Company is also rejecting Mr. Selecky's adjustment to remove capital additions with an in-service date after September 21, 2011. The proposed adjustments listed above that are adopted by the Company are discussed in this section. The proposed adjustments listed above that the Company is rejecting are discussed in the Adjustments Disputed by the Company section below.

Q. Please explain the Company's adjustments to proforma plant additions and retirements, depreciation and amortization expense, and depreciation and amortization reserve.

A. The Company's rebuttal adjustment to capital additions and plant retirements is calculated using actual additions and retirements from July 2010 to March 2011, including the change in the balance in FERC account 106 (unclassified plant). Adjustment 12.13 (Pro Forma Plant Additions and Retirements) in Exhibit RMP__(SRM-2R) also includes updates to the forecast amounts and project in-service dates for the projected April 2011 through June 2012 time period, as provided in the Company's response to Data Request DPU 30.3. In that response the Company provided information regarding projects that were placed into service early or late, that have been delayed past June 2012, or that were not included in the original filing.

Adjustment 12.13 also includes additional amounts to be placed into service for the Transmission Clearance project beyond what was included in the filing; $6.2 million in 2011 and $22.3 million in January 2012 through June 2012. These projects were implemented to comply with both 1) The National Electric Safety Code ("NESC") clearance requirements; and 2) a North American Electric Reliability Corporation ("NERC") Alert released in late 2010. Recent surveys of select lines have identified several spans which, if loaded to published capacity, would violate the allowable NESC clearance. The first phase of clearance correction projects is to correct these potential issues. In late 2010 NERC issued a reliability alert requiring utilities to verify that published line ratings met field conditions. Per the NERC alert, phase two of the clearance correction projects will implement additional line surveys and make corrections where necessary. The NERC alert requires a three year assessment and a three year remediation, with remediation being a year behind assessment. Of the increase in 2011, $3.2 million is due to the first phase and is a combination of additional issues added to the project as well as increased costs. The remaining $3 million increase in 2011 and the $22.3 million increase in January 2012 through June 2012 are due to phase two of this project.

Adjustment 12.13 also includes the retirements related to the sale of transmission assets to Black Hills Power Corporation, the sale of the Snake Creek hydroelectric plant to Heber Light & Power, and the removal of the Condit hydroelectric project, which will be discussed later in my testimony in the Miscellaneous Asset Removal section.

Adjustment 12.16 revises depreciation expense consistent with the changes made to plant in service amounts. Adjustment 12.17 reflects the changes to the depreciation reserve based on changes in depreciation expense, plant additions and plant retirements. Adjustment 12.18 updates deferred taxes based on changes to plant in service amounts.

Miscellaneous Asset Removals

Q. Please provide an overview of your proposed adjustment entitled Miscellaneous Asset Removals.

A. This adjusts the Company's filing for the impacts related to the sale of transmission assets to Black Hills Power Corporation ("BHP"), the sale of the Snake Creek hydroelectric plant to Heber Light & Power ("Heber Power"), and the removal of the Condit hydroelectric project ("Condit Project"). I will discuss each project separately.

Q. Please give a brief description of the sale of transmission plant to BHP.

A. On December 29, 2010, the Company sold ownership interests in certain transmission assets to BHP. Some of the underlying assets sold were existing plant that was in service and some of the assets were planned capital additions and upgrades to existing assets. The Company's original filing properly reflected the future capital additions associated with the transaction at only the amount related to the Company's ownership interest. However, the plant balances and associated expense for the existing assets sold were not excluded in the Company's original request.

Q. Please describe Dr. Jodi Zenger's and Mr. Higgins' recommendations regarding the Company's sale of transmission plant to BHP.

A. Dr. Zenger and Mr. Higgins recommend that the Company's filing be updated to reflect the sale of these assets as they are no longer used to serve customers. At the time of filing their direct testimonies, both the DPU and UAE had pending data requests asking for the actual amounts included in the filing related to the sale. Thus, both Dr. Zenger and Mr. Higgins include placeholders in their testimonies for the sale. Dr. Zenger uses estimated amounts from filings in Oregon, Wyoming and the Federal Energy Regulatory Commission ("FERC"), stating an update to the actual figures will be necessary. Mr. Higgins' direct testimony does not include an actual adjustment; however, he discloses his intent to supplement his testimony once the data is received.

Q. Does the Company agree that an adjustment should be made to reflect the sale of these assets to BHP?

A. Yes. The Company agrees that the filing should fully reflect the impacts of the sale of transmission assets to BHP. In total, this adjustment reduces Utah allocated rate base by approximately $1.6 million and expense by approximately $88 thousand.

Q. On page 6, line 115-116 of Dr. Zenger's testimony, she gives an estimated price for the sale and an estimated gain on the sale. Does she cite how she arrived at these numbers?

A. Yes she does. As stated by Dr. Zenger, those numbers came from an advice filing the Company made with the Oregon Public Utility Commission in October 2010 asking for permission to complete the transaction with BHP, which contained preliminary estimates on the details of the transaction. The Company subsequently filed a compliance filing with the Oregon PUC on January 28, 2011 updating the original estimates to the actual numbers related to the sale to BHP.

Q. Is there any other information regarding the BHP agreement that you would like to add?

A. Yes. The Company and BHP executed a Purchase and Sale Agreement on February 18, 2010. The terms of the agreement state that BHP will be responsible for the costs of their share of these projects. Since the agreement stipulates that the final purchase price will be adjusted at closing for actual costs and expenses related to the additions and upgrades, Utah ratepayers will not bear the responsibility for the costs of the upgrades to the assets sold that are not being used to serve them.

Q. Please give a brief description of the sale of Snake Creek hydroelectric plant to Heber Power.

A. The Company is in the process of selling its Snake Creek hydroelectric generation plant facilities located in Wasatch County, Utah to Heber Power. This transaction is anticipated to close on September 1, 2011.

Q. What is Mr. Higgins' recommendation regarding this sale?

A. Mr. Higgins recommends that the Company's request be updated to reflect the sale of these assets. Mr. Higgins' direct testimony does not include an actual adjustment, but he states his intent to update his direct testimony once he receives the necessary data in a pending data request.

Q. Does the Company agree with Mr. Higgins' proposal that an adjustment should be made to the Company's request to reflect the sale of these assets to Heber Power?

A. Yes. The Company agrees that the filing should fully reflect the impacts of the sale of the Snake Creek hydroelectric plant to Heber Power. Please see Confidential Exhibit RMP__(SRM-4R) for the adjustment details related to Snake Creek.

Q. Did the Company realize a gain on any of the miscellaneous asset sales?

A. [redacted]

[redacted]

Q. Please give a brief description of the removal of the Condit Project.

A. The Condit Project is located in south-central Washington on the White Salmon

River. The Company is moving forward with the decommissioning of the facility after receipt of an essential sediment management permit from the U.S. Army Corps of Engineers ("Corps"), the final major regulatory step. The decommissioning and removal of this facility results from a relicensing process that began in 1991 and culminated in a multi-party settlement agreement in 1999. On Dec. 16, 2010, the Company received a Surrender Order from FERC providing for dam decommissioning. FERC modified the Surrender Order on April 21, 2011, which, along with the Corps permit, provides the regulatory certainty the Company needed to proceed to remove the dam. On June 8, 2011, FERC completed its review and approval of requisite project removal design and resource management plans. Dam removal was determined to be less costly to customers than the fish passage that would be required for operation as part of the federal dam relicensing process. After the initial breach and draining of the reservoir in November 2011, demolition of the remaining portion of the dam is scheduled to begin in the spring of 2012 and be completed by August 31, 2012. Restoration work throughout the former reservoir area is planned to be completed by the end of 2012.

Q. Have any adjustments been proposed related to the removal of the Condit Project in this case?

A. No. During the time of preparing the original filing and the time the intervening parties were preparing their direct testimonies, the Company was in the process of seeking the necessary regulatory approvals to remove the dam. As detailed above, the Company received the necessary regulatory approvals during rebuttal preparation. Therefore, the Company proposes to update the case to reflect the impact of removing the Condit Project. In total, this adjustment reduces Utah allocated rate base by approximately $38 thousand and expense by approximately $323 thousand. The impact of removing the Condit Project is also reflected in the Company's updated net power costs.

Q. How did you incorporate into revenue requirement the adjustments for the sale of transmission assets to BHP, the sale of the Snake Creek hydroelectric plant to Heber Power, and the removal of the Condit Project?

A. The electric plant in service and the accumulated depreciation balances for each asset sold or removed are adjusted in the Pro Forma Plant Additions and Retirements adjustment on page 12.13 and the Depreciation Reserve Update on page 12.17, respectively. Depreciation expense is adjusted for the assets sold or removed in the Depreciation Expense Update adjustment on page 12.16. The accumulated deferred income tax balance impacts are included in the Plant Related Tax Update on page 12.18. The O&M expense and gains associated with the transactions are included in the Miscellaneous Asset Removal adjustment on page 12.14. Confidential exhibit RMP__(SRM-4R) provides the details of each asset sold or removed, summarizing the impacts by FERC account and jurisdictional allocation factor. Finally, the net power cost impacts associated with the Condit Project removal are reflected in the Net Power Costs adjustment on page 12.22.

Bridger and Trapper Mines

Q. Please explain the adjustment to the Trapper and Bridger mine rate base.

A. DPU witness Mr. Croft proposed a modest increase to the Trapper and Bridger rate base amounts. The adjustment increases the Trapper rate base by approximately $307 thousand, the Trapper reclamation liability by approximately $5 thousand, and the Bridger rate base by approximately $441 thousand, resulting in a net rate base increase of $752 thousand on a total company basis, or $320 thousand Utah-allocated. The ratemaking impact of this adjustment increases revenue requirement by approximately $37 thousand. The Company has accepted this adjustment, which is included as Adjustment 12.15 in Exhibit RMP__(SRM-2R).

Q. What is the basis for Mr. Croft's adjustment?

A. At the time of the Company's original filing, the Test Period rate base amounts for the Trapper and Bridger mines were based on actual results for the period June 2009 through September 2010 and forecast results from October 2010 through June 2012. During the discovery phase of this proceeding, the DPU submitted data requests asking the Company provide actual monthly updates as they became available. At the time the DPU filed its direct testimony, the Company had provided actual balances for the months of October 2010 through February 2011. Mr. Croft used these updated actual balances to impute forecast amounts for the Test Period.

Q. How did Mr. Croft impute the forecast amounts for the Test Period?

A. He replaced the forecast monthly balances for the months October 2010 through

February 2011 with the actual amounts. He then revised the each of the monthly forecast balances for the period March 2011 through June 2012 by the incremental monthly difference included in the Company's original filing.

Deferred Income Tax Allocation Correction

Q. Please explain the adjustment to correct the allocation of deferred income taxes.

A. Adjustment 12.19 in Exhibit RMP__(SRM-2R) corrects the allocation factor assigned to various deferred tax items that were incorporated in the original filing. This issue was noted in Company responses to OCS data request 14.1 and DPU data request 7.58, and DPU witness Mr. Croft and OCS witness Ms. Ramas both proposed adjustments to reflect these corrections. The total impact of the correction on revenue requirement was a reduction of approximately $112 thousand.

Cottonwood Coal Lease

Q. Please provide a brief description of the Company's Cottonwood Coal Lease Adjustment?

A. The Company has incorporated the purchase of the Cottonwood coal lease into plant held for future use in Adjustment 12.20 in Exhibit RMP__(SRM-2R). The payments for this coal lease will be made in June 2011 and January 2012. Company witness Ms. Cindy Crane provides more details regarding why it should be included in the Test Period.

Powerdale Decommissioning

Q. Please describe the adjustment Ms. Ramas recommends regarding the Powerdale hydroelectric plant decommissioning project.

A. Docket No. 07-035-93 included an estimated amount of approximately $5.9 million for the cost to decommission the Powerdale hydroelectric plant. The majority of the decommissioning project was completed by the end of 2010 and the actual costs were approximately $4.2 million. Therefore, Ms. Ramas concludes the Company has over-recovered costs associated with Powerdale decommissioning project and recommends the difference between the estimate used in Docket No. 07-035-93 and the amount actually spent of be returned to customers over two years. The Utah-allocated impact of her adjustment reduces revenue requirement by approximately $370 thousand.

Q. Please discuss the Company's response to her proposal.

A. Ratemaking treatment for Powerdale decommissioning costs was unique in that it relied on a forecast of costs prepared several years in advance of the funds actually being spent and related to a project that would span several years.

Q. Does the Company accept Ms. Ramas' adjustment?

A. Yes. The Company accepts Ms. Ramas' proposal for a true-up of the forecast used in Docket No. 07-035-93 to the actual costs incurred for Powerdale decommissioning. This adjustment is included on page 12.21 of Exhibit RMP__(SRM-2R).

Net Power Costs

Q. Have you incorporated any changes to net power costs in the rebuttal revenue requirement?

A. Yes. Company witness Mr. Gregory N. Duvall provides rebuttal testimony related to net power costs and supports specific adjustments to Test Period net power costs in this case. I have incorporated adjustments supported by Mr. Duvall into the rebuttal revenue requirement. Overall, these adjustments reduce Utah allocated revenue requirement by approximately $5.3 million.

Adjustments Disputed by the Company

Line Losses

Q. Did you alter the jurisdictional allocation factors to incorporate Ms. Ramas' recommendation to line losses?

A. No. The Company does not agree with Ms. Ramas' adjustment to the Company's line losses. A full discussion on the Company's position is included in the rebuttal testimony of Mr. Duvall.

Ancillary Revenue

Q. Please describe the adjustment proposed by Mr. Higgins with regards to the contract for ancillary services with Seattle City Light.

A. The Company currently has a contract to provide ancillary services to Seattle City Light that expires on December 31, 2011. Since the contract expires midway through the Test Period the Company removed half of the revenue associated with the contract in its original filing. Mr. Higgins adds that revenue back to the Company's case.

The Company does not agree that leaving revenue in for the entire Test Period is appropriate since the terms and conditions of a new agreement with Seattle City Light, if any, are not known. The Company is currently in negotiations with Seattle City Light on a possible long-term contract to replace the contract that is expiring, and if a new contract is timely finalized it will be included in the Company's surrebuttal filing.

Non-T&D Insurance

Q. Please describe the adjustment proposed by Ms. Ramas regarding non-T&D insurance.

A. Ms. Ramas proposes removing the Swift hydro facility flood damage from the basis for reserve accrual. According to Ms. Ramas, the January 2009 event at the Swift facility was a "unique event that would not occur in a typical year."

Q. Do you feel the Swift flood was an unusual one-time event to be excluded in determining the average cost level to include in base rates?

A. No. Although this identical event is unlikely to occur at the Swift hydro plant again, it is likely that other damages will occur somewhere in the Company's system. The purpose of insurance is to protect against unusual events; each event that is covered by the reserve accrual could be categorized as unusual and non-recurring. But over time, while catastrophic events such as the one at the Swift plant will happen, overall frequency of such events have a measure of continuity and therefore it is a prudent business practice to recover a small amount from customers each year to help levelize these costs.

Q. Could rejecting Ms. Ramas adjustment cause long-term harm to customers?

A. No. As described in my direct testimony on page 26, the Company will be self insured in separate accounts for each jurisdiction. These accounts will be used to record actual damages above the deductible described in my testimony. Any unused reserve balances results in a rate base reduction that will be carried forward into future periods. The question raised in Ms. Ramas' testimony appears to not be whether these costs should be recovered from customers, but whether we should accumulate a balance now, or wait until after a major event occurs. It is the Company's opinion that customers would be better served by accruing a reserve from customers to be used when an event occurs. If the reserve balance goes unused for a period of time, future accruals could be adjusted in a subsequent rate case.

Uncollectible Expense

Q. Please summarize the adjustments proposed to the Company's uncollectible expense.

A. DPU witness Ms. Salter proposes to adjust the Company's uncollectible expense to a five-year rolling average. OCS Witness Ms. Ramas recommends that the Company's uncollectible expense be adjusted to the Company's target rate of 0.27 percent. The proposed adjustments reduce the Company's Utah-allocated uncollectible expense by approximately $367 thousand and $760 thousand, respectively.

Q. How did the Company treat uncollectible expense in its original filing.

A. The Company determined the Test Period uncollectible expense by first calculating the unadjusted uncollectible rate (Utah's FERC 904 expense divided by Utah's general business revenues) and then applying that rate to the Test Period general business revenues. When considering the methodology to use in this case, the Company analyzed the actual June 2010 uncollectible expense to determine the reasonableness of the amount. The Company concluded that the unadjusted June 2010 uncollectible rate was less than the comparable three year average method used in the previous rate case and represented a reasonable level of expense that can be expected during the Test Period.

In Docket No. 09-035-23, the Commission accepted Ms. Salter's recommendation to adjust the Test Period uncollectible expense to a three-year historical average. In this case, the Company discovered that applying that methodology produced an increase to the Company's uncollectible expense. Since the June 2010 level of uncollectible expense seemed to be reasonable, the Company only adjusted the uncollectible expense to account for the additional revenue that will arise as a result of this case. The analysis is highlighted in the table below.

Utah Uncollectible Expense			
	Jun-08	**Jun-09**	**Jun-10**
Utah FERC 904 Expense	$ 4,396,680	$ 5,208,240	$ 4,709,966
Utah General Business Revenue	$ 1,412,248,643	$ 1,420,886,725	$ 1,496,868,201
Uncollectible Rate	**0.311%**	**0.367%**	**0.315%**
		As filed	0.315%
		3 Year Average	0.331%

Q. Ms. Salter claims the Company's method does not take into account the volatility of uncollectible expense. Please address her concern.

A. If Ms. Salter is concerned with volatility, she should have proposed the same adjustment as was done in the last rate case. However, Ms. Salter's adjustment seems to be guided more by trying to get a lower amount than to reduce volatility. The purpose of adjusting uncollectible expense should be to set a reasonable level that will as closely as possible represent the actual expense that will be incurred during the Test Period. As shown in the table above, the base period expense does not seem to be out of line from a historical perspective.

Q. How does Ms. Salter propose to calculate uncollectible expense in this case?

A. Ms. Salter uses a five year rolling average of ten historical uncollectible percentages. Based on this she concludes that a 0.29 percent uncollectible rate is appropriate, which reduces the Company's uncollectible expense by approximately $367 thousand.

Q. How does her methodology proposed in this case differ from the methodology proposed and accepted by the Commission in Docket No. 09-035-23?

A. She changed her methodology from a three year historical average to a five year rolling average that uses ten overlapping data points.

Q. Does Ms. Salter provide sufficient evidence to support her change in methodology?

A. No. She claims a three year average would not properly reflect the recession, which she deems an "anomalous period." Ms. Salter employed this same argument in the last case, and her predictions that the economy would recover during the test period did not materialize. Her argument fails to consider the fact that Utah's economy continues to experience hardships that are not expected to subside for several years. Consequently, the level of uncollectible expense that has been seen in 2008 and 2009 is more likely to reflect the economic conditions that will be present during the time the rates are in effect than the robust economic periods prior to the recession. It is concerning that Ms. Salter's methodology seems to have changed only because the three year average methodology that she recommended in the last case did not produce the same result in this case. Her proposal effectively denies the Company the ability to fully recover its uncollectible expense, which is an unavoidable cost of serving customers. In Docket No. 09-035-23, the Company requested the Commission set a policy in anticipation of this issue. The Company again respectfully requests the Commission set a consistent approach to calculating uncollectible expense, and not base the rate on proposed adjustments designed to come up with the lowest possible forecast for each individual case.

Q. Please describe the adjustment made by Ms. Ramas to the Company's uncollectible expense.

A. Ms. Ramas proposes to adjust the Company's uncollectible expense to the Company's target rate of 0.27 percent. Her adjustment reduces Utah's uncollectible expense by approximately $760 thousand.

Q. Historically has the Commission recognized the use of the Company's target rate as an acceptable methodology for calculating uncollectible expense?

A. No. Past Commission practice has generally not favored the use of the Company's target uncollectible rate for determining uncollectible expense. In my rebuttal testimony in Docket No. 09-035-93, I proposed to use the Company's

0.27 percent target uncollectible rate to set the Test Period level of uncollectible expense as an alternative to Ms. Salter's three year historical average adjustment. In the order in that case, the Commission rejected the Company's proposal to use the target rate stating, "Our general approach to normalize abnormal amounts is to use an average. In this case, therefore, we prefer the Division's use of an historical average over a management forecast."

Glenrock Coal Mine

Q. Do you agree with the adjustment proposed by DPU witness Ms. Salter to remove amortization related to the Glenrock coal mine closure?

A. No. The Company included an adjustment in its initial filing to remove the amortization of the Glenrock coal mine closure from Test Period results. Adjustment 8.11 in Exhibit RMP__(SRM-3) removes $454,856 from operating results, representing $437,818 of amortization in the base period, escalated by 3.89 percent for the Test Period. While Ms. Salter correctly points out that the regulatory asset for Glenrock mine closure costs was fully amortized in September 2010, her adjustment would remove costs that are already excluded from the case.

O&M Expense Escalation

Q. Please explain the adjustment to the escalation of non-labor O&M costs proposed by Mr. Higgins.

A. Mr. Higgins' proposed adjustment removes the increases in non-labor O&M expense as projected by IHS Global Insight (USA) Inc. ("IHS") from the base period through the Test Period. He cites two primary concerns: 1) including a provision for escalation in rates makes inflation a "self-fulfilled prophesy"; and 2) including escalation in the Company's rates builds a "cost cushion" and provides a disincentive for the Company to improve efficiency.

Q. Do you agree with his concerns?

A. No. Mr. Higgins' argument that including a forecast of inflation in the Company's case becomes a self-fulfilling prophesy is overreaching. His proposed adjustment is based solely on his interpretation of high-level economic indicators and not empirical evidence of the cost pressures facing the utility industry. The Company is simply reflecting the cost of goods and services that it will experience during the Test Period. If these cost increases are not reflected in the Company's projected revenue requirement it will impact the Company's ability to recover the cost it will necessarily incur to serve customers during the rate-effective period.

Q. Do you agree that including escalation serves as a "cost cushion" for the Company?

A. No. Planning for the costs the Company will incur in serving customers during the Test Period is not a cost cushion, but a prudent and accepted practice in setting rates that will allow the Company an opportunity to recover its prudently incurred cost of providing safe and reliable electrical service. Adopting Mr. Higgins' adjustment that holds the Company's non-labor O&M flat would only result in chronic under recovery of costs.

Q. What additional arguments does Mr. Higgins provide to support his adjustment?

A. Mr. Higgins claims that inflationary pressures will not be substantial during the Company's Test Period. The source for his claim is the Minutes of the Federal Reserve Open Market Committee for April 26-27, 2011. This document contains high level discussion of national economic factors including core inflation, which is anticipated to be in the range of 1.3 percent to 1.6 percent in 2011 and 1.3 percent to 1.8 percent for 2012.

Q. Why does the Company believe that the IHS escalation factors included in the case are more appropriate than Mr. Higgins' core inflation argument?

A. IHS conducts research that is specialized to the electric utility industry. Based on its research, IHS formulates escalation factors related to specific FERC accounts. In contrast, Mr. Higgins' argument is based on core inflation, which is a broad predictor of inflation that is measured based on aggregate price growth excluding food and energy prices. While core inflation can be a valuable tool when examining the economy as a whole, it is too broad to be an accurate predictor of the specific cost pressures the Company will experience during the Test Period.

Q. Do you have updated inflation expectations for the Test Period?

A. Yes. IHS releases its Global Insight escalation factors on a quarterly basis. The Company's initial revenue requirement calculation used the third quarter 2010 indices (released October 2010), which were the most recent indices available at the time of preparation. Global Insight has since released their fourth quarter 2010 indices (released January 2011) and first quarter 2011 indices (released April

2011).

Q. Does the updated data from IHS align with Mr. Higgins' assertion that inflationary expectations are low?

A. No. Based on current analysis of the electrical utility industry, the expectations for inflation are steadily increasing. Confidential Exhibit RMP___(SRM-3R) compares the escalation factors used in the Company's request to the two more recent releases showing inflation between the base period and Test Period in this case. If the Company were to update the calculation of its requested price increase using the new releases it would increase the O&M escalation adjustment by approximately $273 thousand using the Q4 2010 release and by $3.6 million using the Q1 2011 release on a Utah-allocated basis.

Q. Is the Company requesting to update its request for the new escalation factors?

A. No. Confidential Exhibit RMP___(SRM-3R) is provided to support the Company's assertion that its request is reasonable and conservative considering the fact that an independent research company such as IHS believes cost pressures in the electrical utility industry are increasing.

Q. Can the Company provide other evidence demonstrating an upward trend in expectations for inflation?

A. Yes. Mr. Higgins' source for core inflation actually supports the Company's assertion that expectations for inflation have steadily increased. Although the Company does not believe that core inflation is the best measure of inflationary pressures the Company will be faced with, comparing the Minutes of the Federal

Reserve Open Market Committee from June 2010, November 2010, January 2011, April 2011, and June 2011 reveals an interesting trend in the expectations of the Federal Reserve Governor and the Reserve Bank Presidents. The following table provides a comparison of the core inflation projections from Table 1 contained within the minutes released by the Federal Reserve:

Economic Projections of the Federal Reserve Governor & Reserve Bank Presidents		
	Core Inflation Range	
Release Date	*CY 2011*	*CY 2012*
June 22-23, 2010	0.8 to 1.0	0.9 to 1.3
November 2-3 2010	1.0 to 1.1	0.9 to 1.6
January 25-26, 2011	1.0 to 1.3	1.0 to 1.5
April 26-27, 2011	1.3 to 1.6	1.3 to 1.8
June 22, 2011	1.5 to 1.8	1.4 to 2.0

The O&M escalation adjustment based on IHS indices included in the original filing amounts to an increase that is less than two percent annually, an amount that is supported by the table above.

Q. Please describe the Commission's treatment of this issue in past general rate cases.

A. In Docket No. 07-035-93 the Commission examined this issue and determined that the Company's use of Global Insight indices was "appropriate and provide the Company adequate incentive to manage their non-labor O&M costs (other than net power costs)." This is also the treatment that was used by the Company in Docket Nos. 08-035-38 and 09-035-23.

Q. Please describe the adjustment Mr. Garrett makes to the Company's O&M escalation adjustment.

A. Mr. Garret proposes to include an efficiency adjustment savings of 0.5 percent per year as an offset to the Company's O&M escalation adjustment. He claims this acts as an incentive for the Company to control its costs.

Q. Do you find Mr. Garrett's proposal to be reasonable in this general rate case?

A. No. Mr. Garrett's approach to O&M escalation does not afford the Company the opportunity to recover the costs it will likely incur to serve customers during the rate effective period in this case.

Q. Is an efficiency adjustment necessary in this case?

A. No. As discussed earlier, Confidential Exhibit RMP___(SRM-3R) shows that updating to the latest release would increase the Company's revenue requirement by approximately $3.6 million Utah-allocated. Based on this, it is evident that the level of non-labor, non-NPC O&M expense included in the case as escalated will likely be substantially lower than the cost increases the Company will actually face during the Test Period. Thus, the Company will need to find efficiencies just to be able operate within the amount included in the original request. Mr. Garrett's efficiency adjustment is not necessary and will only penalize the Company for costs outside its control.

Q. Can you provide an example of such a cost?

A. Yes. In June 2011, the Company was notified that its Utah Public Utilities Regulation fee for fiscal year 2012 had increased by over $1.2 million, or 38 percent, as compared to the fee assessed for fiscal year 2011. The fee is calculated by multiplying the amount of operating revenues for the preceding calendar year by an assessment rate. While part of the year over year increase resulted from increased operating revenues, the majority of the increase was due to the fact that the assessment rate was increased by over 27 percent more than the previous year. This is just one example of an increased operating expense that is outside of the Company's control that will have to be absorbed by other operating efficiencies.

Q. What evidence does Mr. Garrett provide to support his calculation that an appropriate level for an efficiency adjustment is 0.5 percent?

A. Mr. Garrett supports this number by stating that the Company has used a similar productivity offset in its post-test year attrition ratemaking adjustment filings in its California jurisdiction. Therefore, he claims the same type of adjustment is warranted in Utah when a forecasted test year is used.

Q. Do you agree with this argument?

A. No. The regulatory environment in which the Company operates in the state of California is vastly different than in Utah. The California Commission requires the Company to file general rate cases every three years in California. Between rate cases, a variety of mechanisms are approved for use by the Company in California as a way to recover prudently incurred costs. One of such mechanisms is the one referred to by Mr. Garrett called the Post-Test Year Ratemaking Adjustment ("PTAM") mechanism. The PTAM Attrition is a mechanism which enables the Company to timely recover prudently incurred cost increases without filing a general rate case. PTAM Attrition filings are specific mechanisms for use by the Company in California that do not examine every individual revenue requirement component and cannot be compared to a general rate case in Utah.

Q. Can the Company provide any examples of other jurisdictions where the Company's requested O&M escalation methodology is utilized?

A. Yes. Oregon and Wyoming utilize forecast test periods, and the Company makes an O&M escalation adjustment in its rate cases in those states. No productivity offset is required in those states.

Cash Working Capital

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

A. Yes. Mr. Garrett addresses the cash working capital issue raised in Docket No. 07-035-93. In its final Order, the Commission did not adopt the 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 all of them together, not in the piecemeal manner done by Mr. Garrett.

Q. Did the Company prepare the December 2007 lead lag study consistent with the Commission's current cash working capital policy ("CWC")?

A. Yes. Consistent with the Commission's CWC policy,[4] 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 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 for 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

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

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 sometimes 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, which is recovered 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. Mr. Robert L. Hahne addresses this issue in his book, <u>Accounting for Public Utilities</u>, 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 **<u>not</u>** to consider the operating income component in the lead/lag study and **<u>not</u>** to recognize accruals of interest as a source of cash working capital.[5] 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 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

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

calculation of cash working capital.

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 for 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.

Capital Related Adjustments

Q. Please explain your understanding of Mr. Croft's proposal to update the composite depreciation rates and recalculate the retirement rates included in the filing.

A. In Mr. Croft's plant related adjustments, he updates the composite depreciation rates to use December 2010 plant-in-service balances, instead of using the composite depreciation rates contained in the filing which are calculated using June 2010 plant balances. Mr. Croft also recalculates the average retirement rate to exclude one year, proposing a four year average rather than the five year average the Company has used in the filing.

Q. Do you agree with Mr. Croft's proposal to update the composite depreciation rates?

A. No. The composite depreciation rates included in the filing are developed using plant-in-service balances by function and factor and the Commission approved depreciation rates for depreciable property. The depreciation rates were approved by the Commission in Docket No. 07-035-13 and were effective January 1, 2008. In the filing, the June 2010 plant balances were used to calculate the composite depreciation rates to match the June 30, 2010 base period in the case. Since there has not been a change in the depreciation rates that were previously approved by the Commission, there is no reason to update the composite depreciation rates to use December 2010 plant balances. Furthermore, Mr. Croft has not provided evidence as to why it is better to use the December 2010 composite rates.

Q. Do you agree with Mr. Croft's proposal to recalculate the average retirement rates?

A. No. The retirement rates included in the filing are average retirement rates based on five years of retirement data. The retirement rate for each year is calculated by taking the retirements divided by the plant-in-service balances. The Company's average retirement rate calculation included the following five periods: Apr05-Mar06, Apr06-Dec06, Jan07-Dec07, Jan08-Dec08, and Jan09-Dec09. Mr. Croft proposes to remove the April 2006 through December 2006 period from the average calculation since it only includes nine months. The reason this particular year contains nine months instead of twelve months is due to the Company moving from a fiscal year ended March to a year ended December. The Company did not want to give more weight to the January 2006 through March 2006 retirements by including those retirements in two separate periods. Since he excludes the April – December 2006 period, Mr. Croft's four year average is missing a period in the middle of the average calculation. This makes it appear as though he is cherry picking which years to include.

Q. Do you have any other concerns with Mr. Croft's proposal?

A. Yes. Virtually all parts of the Company's revenue requirement could be updated, including inflation rates discussed above. Although it makes sense to update the rate case for known major changes after the rate case is filed, it would be administratively difficult to update all components.

Q. Do you agree with the adjustment proposed by OCS witness Ms. Ramas to reduce April 2011 through June 2012 projected capital additions by 4.34 percent?

A. No. Ms. Ramas compares total Company actual plant additions for July 2010 through March 2011 to the amounts forecasted in the Company's case and concludes that because the total plant placed in service is 4.34 percent lower than the amount forecasted for the same period, all forecasted capital additions for April 2011 through June 2012 included in the Company's filing should be reduced by 4.34 percent. The Company does not agree with this blanket reduction to plant additions without regard to individual project status. Ms. Ramas' adjustment fails to take into consideration projects from the July 2010 through March 2011 period that have been delayed into the April 2011 through June 2012 period. Ms. Ramas' adjustment also does not take into account new projects that may have replaced projects that were cancelled or delayed past June 2012. Ms. Ramas' adjustment decreases capital in every functional category without consideration as to whether that functional category had more or less placed into service than what was in the Company's original filing.

Q. Are there projects in the capital forecast that had been delayed from the July 2010 through March 2011 timeframe into the April 2011 through June 2012 period?

A. Yes. In data response DPU 30.3 the Company provided information for projects that were forecast for July 2010 to March 2011 that were delayed into the April 2011 through June 2012 timeframe. Ms. Ramas' position does not take into consideration eight projects that were identified in that response that total approximately $35 million. Those projects need to be pushed into the later months of the forecast as those projects have not been cancelled, just delayed.

Q. Are there any new projects that will be placed into service during the April 2011 through June 2012 period?

A. Yes. In data response DPU 30.3 the Company identified seven projects that were not included in the original filing, but that are forecast to be placed into service in the April 2011 through June 2012 period, totaling approximately $32 million. Ms. Ramas' position does not take these projects into consideration.

Q. Do you have any concerns with Ms. Ramas' adjustment to depreciation expense?

A. Yes. In her adjustment, Ms. Ramas reduces depreciation expense in the mining function by approximately $1 million total Company and $0.4 million Utah allocated. In the depreciation expense adjustment included in the filing, the Company did not include an adjustment to mining depreciation expense because it goes through the cost of fuel (coal) in the net power cost study. Ms. Ramas' adjustment should be reduced by approximately $0.4 million Utah allocated to remove the decrease to mining depreciation expense.

Q. Please explain the adjustment proposed by UIEC witness Mr. Selecky related to capital additions.

A. Mr. Selecky proposes to remove post September 21, 2011 capital additions because the additions are projected to be placed into service after the rate increase in this case becomes effective.

Q. Do you agree with Mr. Selecky's adjustment?

A. No. In its order on Test Period in this docket the Commission states, "we must also consider the predicted substantial increases in plant investment the Company forecasts to be necessary in early 2012, particularly the significantly increased investment projected as necessary for compliance with air quality requirements." In testimony Mr. Selecky acknowledges the significant capital additions for pollution control and transmission projects in April 2012, May 2012, and June 2012, but still proposes an adjustment to remove all of those additions. Mr. Selecky's adjustment appears to be an attempt to overturn the test period order in this case which approved a test period ending June 2012 with average rate base. In addition his proposed adjustment is not reasonable because he essentially ignores over nine months of plant additions in the Test Period. The Company should be given a reasonable opportunity to recover its costs, and a blanket type adjustment as Mr. Selecky has proposed does not allow the Company to recover its costs for those capital investments, and is inconsistent with the Test Period used in this case. The forecast capital projects to be placed into service September 22, 2011 through June 30, 2012 will be providing customers with benefits through the rate effective period and the Company should be allowed the opportunity to recover those amounts from ratepayers. The capital additions are necessary and prudent to provide reliable and safe service for our customers. Failure to include these investments in rates understates the cost of serving customers and puts significant financial pressure on the Company.

The Company is using 13 month average rate base for the Test Period so assets that have an in service date at the end of the Test Period will only have a portion of the amount included. For example, assets that are included with a May 2012 in service date would only have 2/13 of its forecasted amount included in the case.

Q. Do you have any issues with the calculation of the adjustment proposed by UIEC witness Mr. Selecky to remove post September 21, 2011 projected capital additions?

A. Yes. Mr. Selecky's $974,000 property tax adjustment as shown on Exhibit UIEC JTS-4 is overly simplistic and incorrect for the following reasons. First, Mr.

Selecky fails to account for the fact that property taxes pertaining to each capital project with cumulative expenditures in excess of $5 million as of each year's lien date are capitalized into the cost of such projects. Accordingly, Mr. Selecky's proposed adjustment has the effect of removing from property tax expense amounts not charged to expense. Second, Mr. Selecky fails to account for the fact that certain projects expected to be placed in service after September 21, 2011 involve the installation of pollution control equipment at the Company's Wyoming generating plants. Such property is exempt from property taxation in Wyoming. The estimation processes employed by the Company when estimating property tax expense take these and other similar items into account.

Q. Do you have any other comments regarding updating forecasted capital additions with actual capital additions for July 2010 through March 2011?

A. Yes. In the original filing removal costs were included in some of the Company's capital project forecasts. However, actual removal costs reduce the accumulated depreciation reserve balance, thus increasing rate base, but these costs were not included as plant additions in the Company's response to DPU 30.3. Actual removal costs for July 2010 through March 2011 related to generation projects total $23 million. When removal costs are included, as of the end of March 2011 actual plant additions are only $47 million lower than forecasted, rather than $70 million. Since removals are a new issue in the rate case the Company has not included those removals in its rebuttal position. The Company has provided information here about the removals to support the Company's assertion that its capital project rebuttal position is reasonable and conservative considering the

Company's rebuttal position could be increased by $23 million. This is further evidence why Ms. Ramas' adjustment to reduce the April 2011 to June 2012 capital additions by 4.34 percent and Mr. Selecky's adjustment to remove over nine months of capital should both be rejected.

The Company is continually analyzing the capital needs of the electrical system to determine which investments are required to maintain and provide 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, thus changing the mix of plant additions from what was included in the original rate case filing.

The approach taken by the DPU related to the April 2011 to June 2012 forecasted capital additions is more appropriate for this case because it looks at individual project forecasts and timing. Ms. Ramas' position disregards possible changes in the timing of projects being placed into service and should be rejected. Mr. Selecky's position does not allow the Company to recover costs for prudent capital investments which will provide benefits to customers through the rate effective period.

Q. UIEC witness Dennis Peseau proposed an adjustment to remove 50 percent of the Populus to Terminal transmission line from rate base. Does the Company accept the adjustment, and did he calculate his adjustment correctly?

A. No. As stated in the rebuttal testimony of Company Witness Mr. John Cupparo, the Company rejects Mr. Peseau's adjustment completely. In addition, Mr.

Peseau has not correctly calculated his adjustment to remove 50 percent of the Populus to Terminal project from this filing. It appears as though Mr. Peseau has used a rate base amount of $819 million for the project which was provided in a data response in the Company's recent Wyoming general rate case. This amount is different than the rate base amount included for the Populus to Terminal project in the Utah general rate case. Mr. Peseau also has not taken into account the Company's use of 13 month average rate base in this filing. It also appears as though Mr. Peseau has assumed no bonus depreciation for the Populus to Terminal project, which is also incorrect. Mr. Cupparo and Mr. Gerrard provide additional testimony regarding the impropriety of Mr. Peseau's adjustment.

Klamath Hydroelectric Settlement Agreement

Q. Please summarize the Company's position related to the Klamath Hydroelectric Settlement Agreement ("KHSA").

A. The KHSA represents a beneficial outcome to a complex and challenging process resolving the issues surrounding the Company's assets located in the Klamath basin region. The rebuttal testimony of Mr. Dean S. Brockbank provides more detail on the Company's policy relating to Klamath.

Q. In the rebuttal testimony of Mr. Brockbank, he states that the KHSA benefits all of the Company's customers. Can you provide support for his statement?

A. Yes. The Company compared the cost of the KHSA with the costs expected under a conservative relicensing scenario. Since the costs of relicensing are highly uncertain, the Company developed a baseline relicensing case against which the economics of the KHSA were compared. The baseline relicensing case relies heavily on the costs and data developed as part of the FERC Final Environmental Impact Statement (“FEIS”).

Q. How was the analysis structured?

A. The analysis evaluated the present value revenue requirement (“PVRR”) of the stream of costs under the KHSA and compared it against the PVRR of the stream of costs under the baseline relicensing scenario. The analysis covered a 44-year period beginning in 2010 – this equates to a 40-year license beginning in 2014. The results of this analysis are summarized in Confidential Exhibit RMP__(SRM-5R). The analysis was shared with Utah parties at a technical conference on February 15, 2011.

Q. Does the KHSA result in a fair and balanced outcome to the Company’s Utah customers?

A. Yes. Based on the outcome of this conservative analysis, the KHSA results in a PVRR that is below the cost of relicensing. More importantly, customers are protected from the risks and liabilities that exist absent an agreement among the parties. These risks include: (1) far higher costs under final terms and conditions for relicensing; (2) the inability to secure state and federal approvals for relicensing; (3) continued litigation related to endangered species act requirements and water quality issues; and (4) early shut-down and removal of the project. In the end, the terms of the KHSA allow the Company to protect its customers in the long term from the potential economic impact and risks of relicensing.

Q. What adjustments are recommended by the intervening parties with regards to the KHSA?

A. DPU witness Dr. Powell opposes the accelerated depreciation of the existing Klamath assets, suggests a 20 year depreciation life of the relicensing costs, and recommends situs treatment of the surcharge under the Rolled In allocation methodology. UAE witness Mr. Higgins opposes the accelerated depreciation of the existing Klamath assets and recommends Utah customers not pay for the KHSA surcharge. OCS witness Ms. Beck recommends a complete disallowance of all KHSA related items.

Q. Does the Company agree with Dr. Powell and Mr. Higgins contention that it is premature to change the depreciation rates for existing Klamath hydroelectric project assets?

A. No. Mr. Brockbank responds to Dr. Powell's and Mr. Higgins' proposals and supports the Company's position based on the details of the KHSA. The Company continues to request the Commission's approval in this case of an accelerated depreciation schedule that would depreciate the Klamath facilities on a straight-line basis such that the net book value reaches zero by December 31, 2019, prior to possible dam removal.

Q. What is the impact on this case related to accelerating the depreciation of the existing Klamath facilities?

A. Page 8.12.2 of Exhibit RMP___(SRM-3) that accompanied my direct testimony details the depreciation expense calculation for existing Klamath facilities, with the accelerated rates effective January 1, 2011. The accelerated rates result in additional Test Period depreciation expense of approximately $4.5 million on a total Company basis, or $1.9 million on a Utah-allocated basis in this case. If the change to depreciation rates is postponed, the impact on rates will increase exponentially because of the fewer number of years to depreciate the plant.

Q. Dr. Powell supports his recommendation by saying, "Since the Company has stated it plans on filing annual rate cases for the foreseeable future, the Company can introduce the Klamath issue in the next rate case with little incremental impact on rates". Why is this not preferable treatment from the perspective of Utah ratepayers?

A. The timing of the Company's future rate cases is not a valid reason to delay the accelerated depreciation. With a terminal date for the Klamath facility specified in the KHSA, delaying the recovery only shortens the time-span for which costs are recovered and increases the impact to customers.

Q. Dr. Powell recommends the depreciation life of the relicensing costs be extended from 10 years as requested by the Company to 20 years. Is this beneficial to ratepayers?

A. Under the KHSA, the Klamath dam will be operational through the decommissioning in 2020. Setting the depreciation of the assets to be fully depreciated by 2020 assigns the costs of the Klamath project to the customers who will benefit from the project prior to its decommissioning and prevents those costs from being pushed to future ratepayers who will no longer be benefitting from the resource. Ratepayers today might benefit from a longer depreciation life, but this benefit comes at the expense of future ratepayers. His recommendation misaligns the benefits with the costs causing intergenerational subsidies.

Q. Please explain Dr. Powell and Mr. Higgins' positions on how the surcharge and removal costs should be allocated.

A. Both Dr. Powell and Mr. Higgins recommend the removal costs be directly assigned to California and Oregon under the Rolled In methodology.

Q. Are these costs appropriately allocated under the definition of the Rolled In methodology?

A. Yes. Under the Rolled In methodology, the costs associated with a system resource should be allocated system-wide. Since Klamath is a system resource, system allocation of its costs is both appropriate and reasonable as it is no different than any of the Company's other hydroelectric generation facilities on the west side of the system. The parties in this case all advocate for the Rolled In methodology. Under their prescribed methodology, the costs associated with the KHSA represent system costs.

Q. Do you agree that the revenue collected from Oregon and California ratepayers related to the KHSA surcharge should be allocated to Utah's ratepayers?

A. No. The removal of the Klamath project as described by Mr. Brockbank will be done because it is in the best interest of all customers, not just customers in Oregon and California. The revenue collected under the Oregon and California surcharge is state specific revenue collected under a separate tariff. Revenue collected in other states is irrelevant to the costs that are allocated to Utah under a multi-jurisdictional allocation methodology. Just as the revenues collected from Utah ratepayers does not affect the costs that are allocated to other states. KHSA dam removal costs are system costs that are appropriately allocated to Utah under the Rolled In methodology.

Q. Please summarize the OCS position on the costs associated with the KHSA.

A. The OCS contends that KHSA costs should not be included in this rate case because the costs 1) were incurred to satisfy regional interests; 2) are uncertain due to unmet conditions contained within the KHSA; and 3) have not received adequate regulatory review. The first and second concerns listed above are addressed in detail in the rebuttal testimony of Mr. Brockbank. I will address her third concern.

Q. Is Ms. Beck's statement that the KHSA and its applicable costs have not received adequate regulatory review a valid argument?

A. No. Through the MSP Docket No. 02-035-04, the Klamath issue has been an ongoing subject of discussion. Since the Company filed for approval of the 2010 Protocol methodology, Klamath has been even more heavily addressed. The Company held a technical conference with Utah parties on February 15, 2011 focusing on the KHSA. In addition, the Company has responded to significant discovery in Utah with regards to Klamath. Delaying the recovery of the KHSA will only shorten the period over which the costs are recovered.

FERC Wheeling revenues

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

A. No. The Company's transmission rate case, filed with FERC on May 26, 2011, under docket number ER11-3643, proposes updated wholesale rates for transmission and other ancillary services provided under the Company's Open Access Transmission Tariff ("OATT"). To date, no procedural schedule for discovery, settlement or hearing has been set. Due to often lengthy settlement processes at FERC to resolve rate cases, the Company is not able to calculate the date FERC will issue an order approving the Company's request for OATT rate changes. It is possible that FERC will allow the Company's proposed rate changes to be made effective prior to issuance of an order; however, any such rates would be subject to refund pending the conclusion of the FERC proceeding. As a result, the Company has not proposed any wholesale revenue credit adjustments for this case ensuing from the transmission rate case filing.

Since the Company does not know the amount or timing of a FERC decision and the subsequent effective date for the approved rates, the Company proposes deferring Utah's share of any rate increase granted by FERC until the next Utah rate case. The Company does not anticipate this amount to be significant. The Company included in its transmission rate case filing a customer impact statement which shows OATT revenues using the proposed rates applied to historic loads. The impact statement indicates approximately $1.3 million in incremental annual third-party transmission revenues and $1.7 million in incremental annual ancillary service revenues under the proposed rates, exclusive of any short-term or non-firm revenues. On a Utah-allocated basis, assuming the new rates are permitted to be made on an interim basis effective January 2012, would only amount to approximately $650,000 Utah allocated in the Test Period assuming the full requested increase is granted.

REC Revenue Deferral – Post Docket 10-035-124

Q. Did any of the parties to this case discuss REC deferral or tracking mechanisms?

A. Yes. Ms. Salter for the DPU and Ms. Ramas for the OCS both recommended mechanisms to account for the difference between actual REC revenues and the amounts included in rates from this case. According to Ms. Salter:

> "the Division is recommending a REC Tracker be established in order to help alleviate the fluctuation the Company is seeing in its market REC price…. To simplify the process, the tracker could be structured in a way that filings and rate adjustments would follow the Company's recently implemented energy balancing account (EBA). This would enable the REC revenues to be trued up at the same time as the EBA expenses. The Division believes the best approach would be to have the two programs run parallel to each other but reported in separate dockets."[6]

Ms. Ramas made the following proposal:

> "I recommend that RMP be required to record the difference between the amount of REC revenues approved by the Commission in this case for inclusion in rates and the actual REC revenues realized, with any differences being recorded in a regulatory deferral account…. At the time of the next rate case following this case, any deferred balance would be amortized as part of the revenue requirement."[7]

Q. What is the Company's position regarding the DPU and OCS proposals?

A. The Company agrees that due to the current uncertainty in the REC market a mechanism would be appropriate, and would urge the Commission to adopt one of the proposals.

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[6] Direct testimony of Brenda Salter, page 13, lines 233 – 241.
[7] Direct testimony of Donna Ramas, page 36, lines 787 – 790 and 799 – 801.

Q. What is the Company's preferred approach?

A. Although the Company believes both proposals have merit and are acceptable, the Company would prefer the DPU approach because it outlines the timing of REC filings and aligns rate changes with those of the Energy Balancing Account ("EBA"). The reason for this preference is because when the Company files the next rate case it may only have a few months of actual data, and would need to provide an estimate for the remaining time until the new rates from the next case go into effect. Although some of the estimates could be trued up during the case, the ultimate true up would need to be in a later rate case filing. For this reason, the Company would prefer the DPU approach using the same filing dates as the EBA.

REC Revenue and Net Power Cost Deferrals

Q. What is the Company's position regarding net power cost ("NPC") and REC deferrals from February 2010 through September 2011?

A. As described in my supplemental direct testimony on deferred accounts, the Company believes that starting the amortization of both the deferred NPC and deferred REC accounts simultaneously is in customers' interest.

Q. Was the amortization of the REC and NPC deferred balances addressed in the intervenor direct testimony in this rate case?

A. Yes. The amortization of the deferred REC balance was addressed in the testimony from the OCS and UAE, but neither they nor any other party addressed the issue of the deferred NPC balance.

Q. When did the Company begin deferring Utah allocated REC revenue and deferred NPC?

A. Pursuant to the Commission's July 14, 2010 Report and Order on Deferred Accounting Stipulation in Docket Nos. 09-035-15 and 10-035-14, the Company has deferred incremental NPC in a deferred NPC account from February 18, 2010 and incremental REC revenue in a deferred REC account from February 22, 2010.

Q. What position was taken by parties on the amortization of the deferred REC balance in their testimony in this case?

A. The OCS and UAE each requested that the Commission determine the ratemaking treatment of the balance in the deferred REC account as part of this case. The OCS requested that the balance (as reported by the Company on the last day of hearings in the case) be amortized over a period of three years starting on September 21, 2011, with the amount trued up to actual accruals through September 20, 2011. UAE requested that the balance that had accrued in the deferred REC account through December 31, 2010, be amortized from September 21, 2011 through September 20, 2012 and that the balance accruing from January 1, 2010 through September 20, 2010 be amortized from September 21, 2012 through September 20, 2013.

Q. What is the magnitude of the REC and NPC deferrals recorded by the Company?

A. Confidential Exhibit RMP___(SRM-6R) shows the actual deferrals for calendar year 2010, and projected deferrals for calendar year 2011. The balance in the deferred REC account from February 22, 2010 through December 31, 2010 was approximately $39 million. The Utah-allocated deferred NPC from February 18, 2010 through December 31, 2010 is approximately $54 million, prior to any consideration of use of the Rolled In allocation method as discussed in the EBA Order.

The Company estimates that as of September 21, 2011, the date rates set in this general rate case will go into effect, the balance in the deferred REC account will be approximately $37 million, and the balance in the NPC deferral account will be approximately $157 million.

Q. Does the Company believe that it would be in the customers' or Company's best interest to start amortization of the REC deferral and not the NPC deferral?

A. No. As described in my supplemental direct testimony, if the Commission determines the ratemaking treatment of the balance in the deferred REC account as part of this case, it should also determine the ratemaking treatment of the balance in the deferred NPC account as part of this case. To provide customers with a potential rate sur-credit based on the deferred REC account balance while holding the potential rate surcharge associated with the deferred NPC account balance that accumulated over the same time period for later treatment would not be appropriate and would simply delay the recovery of the deferred NPC to a later period when there may not be an offsetting credit.

Q. In responses to your supplemental testimony and the Company's Motion for Determination of Ratemaking Treatment of Deferred Accounts, other parties have argued that the Company should not be allowed to recover the Deferred NPC Account as a matter of law. Do you agree?

A. No. I do not intend to argue the legal issues in this testimony. However, I believe it would be appropriate to respond to factual issues underlying the positions of the other parties.

There is no underlying factual difference between the Deferred NPC Account and the Deferred REC Account. Both are the result of the fact that the Company, the parties and the Commission were unable to accurately predict the amount of NPC and REC revenue that would be incurred during the period rates set in the last general rate case have been in effect. The differences between the amounts included in rates and the amounts incurred were significant and substantial in both cases. Neither constitutes a normal deviation from projections of amounts included in rates. The fact that the Commission granted deferred accounting for both amounts already reflects these facts.

The issue before the Commission in determining the ratemaking treatment of the deferred accounts is whether the amounts deferred are reasonable and prudent. This issue is no different for the Deferred NPC Account than it is for the Deferred REC Account. Parties have raised questions in their direct testimony regarding the prudence of certain items within the Company's NPC. Parties have also raised questions about whether the Company was prudent in its management of its RECs. Other witnesses for the Company have responded to these issues in their rebuttal testimony. These issues are the same issues that the Commission will address in deciding whether recovery of all or some portion of the deferred accounts is appropriate.

Q. Does this conclude your Testimony?

A. Yes.