- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	)	DOCKET NO. 09-035-23 REPORT AND ORDER ON REVENUE REQUIREMENT, COST OF SERVICE AND SPREAD OF RATES

ISSUED: February 18, 2010

SHORT TITLE

Rocky Mountain Power 2009 General Rate Case
Phase I Order on Revenue Requirement and Cost of Service
using June 2010 Forecast Test Period

SYNOPSIS

The Commission increases Rocky Mountain Power's annual revenue requirement by $32.4 million, based on a forecasted test period of 12 months ending June 2010 and an allowed rate of return on equity of 10.60 percent. This is a 2.2 percent increase in Rocky Mountain Power's forecast of general business revenue in Utah. The Commission approves a non-uniform percentage increase to be applied to certain tariff customers' bills as a line item for service prior to the Commission's determination of rate design in Phase II of this docket.

TABLE OF CONTENTS

DOCKET NO. 09-035-23

APPEARANCES:

Paul J. Hickey, Esq. Hickey & Evans, LLP Katherine A. McDowell, Esq. McDowell & Rackner, PC Yvonne R. Hogle, Esq. PacifiCorp	For	PacifiCorp
Michael L. Ginsberg, Esq. Patricia Schmid, Esq. Assistant Attorneys General	"	Division of Public Utilities
Paul H. Proctor, Esq. Assistant Attorney General	"	Office of Consumer Services
Gary A. Dodge, Esq. Attorney at Law Hatch, James & Dodge	"	UAE Intervention Group
F. Robert Reeder, Esq. Attorney at Law Parsons Behle & Latimer	"	Utah Industrial Energy Consumers
Holley Rachel Smith, Esq. Attorney at Law Russell W. Ray, PLLC	"	Wal-Mart Stores, Inc.
Kurt J. Boehm, Esq. Attorney at Law Boehm, Kurtz & Lowry	"	Kroger Co.
Dale F. Gardiner Attorney at Law Van Cott, Bagley, Cornall & McCarthy	"	Utah Farm Bureau Federation

I. PROCEDURAL HISTORY

On April 16, 2009, Rocky Mountain Power ("Company"), a division of PacifiCorp, filed its notice of intent to file a general rate case on or about June 15, 2009. The Company also requested approval of a forecast test period ending December 31, 2010, using 13-month average rate base, provided supporting testimony for its test period proposal, and requested the Commission set a procedural schedule which would provide the Commission's decision on test period by May 15, 2009.[1]

Between April 29, 2009, and September 14, 2009, the following parties petitioned for leave to intervene in this case which the Commission granted: Holcim, Inc., Kennecott Utah Copper Corp., Kimberly-Clark Corp., Malt-O-Meal, Praxair, Inc., Proctor & Gamble, Inc., Tesoro Refining and Marketing Co., and Western Zirconium, collectively referred to as Utah Industrial Energy Consumers ("UIEC"); the Utah Association of Energy Users, ATK Space Systems, American Pacific Corporation, Chevron U.S.A., Inc., ConocoPhillips Gas and Power, Hexcel Corporation, IHC Health Services, Inc., IM Flash Technologies, LLC, May Foundry & Machine Company and Simplot Phosphates, collectively known as UAE Intervention Group ("UAE"); Western Resource Advocates ("WRA"); the International Brotherhood of Electrical Workers, Local 57 ("IBEW Local 57"); Nucor Steel-Plymouth, a Division of Nucor Corporation ("Nucor"); the Kroger Co. ("Kroger"); Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively, "Wal-Mart"); Salt Lake Community Action Program ("SLCAP"); the Utah Farm Bureau

[1] The terms "test period" and "test year" are used interchangeably throughout this order.

Federation ("Farm Bureau"); Utah Clean Energy ("UCE"); Southwest Energy Efficiency Project ("SWEEP"); and US Magnesium LLC ("US Mag").

Upon request, on April 22, 2009, the Commission issued a Protective Order in this case. On April 23, 2009, a duly noticed scheduling conference was held. On April 30, 2009, the Company filed direct testimony in support of its proposed test period ending December 31, 2010. On May 13, 2009, the Division of Public Utilities ("Division"), on behalf of the Division, Company, the Office of Consumer Services ("Office"), and Utah Energy Users notified the Commission of a tentative settlement agreement on test year, requested the Commission extend the filing date for test year testimony until May 19, 2009, and preserve the May 21, 2009, test year hearing date to conduct a hearing on the stipulation, if executed and filed, or, in the alternative, a hearing on test year.

On May 14, 2009, the Company filed a Test Period Stipulation executed by the Company, the Division, the Office, UIEC, and UAE, and a motion for approval of the Stipulation. In addition, the Commission issued both a Test Period Scheduling Order which set a schedule for the filing of testimony and established a date for the hearing on test period, and Notice of Test Period Stipulation.

On May 21, 2009, the hearing on the Test Period Stipulation was held and the Company filed an updated Stipulation signature page showing the signature of UIEC's representative. On June 1, 2009, the Commission issued a Report and Order on Test Period Stipulation approving the twelve-month period ending June 30, 2010, using a 13-month average rate base, as the test period in this case.

On June 4, 2009, the Company filed two notices of appearance of attorneys licensed in a foreign state.

On June 23, 2009, the Company filed an application for a revenue increase of approximately $66.9 million based upon a forecast test period beginning July 1, 2009, and ending June 30, 2010, using a 13-month average rate base, and a return on equity of 11.00 percent. The Company proposes the new rates based upon this revenue increase become effective on February 18, 2010. The application includes direct testimony on capital structure and capital costs, load and retail sales forecasts, revenue requirement, cost of service, revenue spread to rate schedules, rate design, and modifications to the Utah Electric Service Schedules.

On July 7, 2009, the Commission issued a Notice of Scheduling Conference to be held on July 14, 2009, to determine the procedural schedule in this docket and Wal-Mart filed a Notice of Appearance of an Attorney Licensed in a Foreign State. On July 8, 2009, UIEC filed a Motion to Bifurcate Proceedings ("Motion") into two phases, a revenue requirement phase and a cost-of-service, rate spread and rate design phase. On July 14, 2009, a duly-noticed scheduling conference was held. On July 22, 2009, the Division filed a response to UIEC's Motion. On July 23, 2009, the Office filed a response in opposition to UIEC's Motion and the Company filed a response to UIEC's Motion. On July 27, 2009, UAE filed a joinder of UAE in UIEC's Motion.

On August 3, 2009, UIEC filed a Reply in Support of UIEC's Motion to Bifurcate Proceedings. On August 4, 2009, the Commission issued both an Order on Motion to Bifurcate and a Scheduling Order setting the procedural schedule for this case. On August 6, 2009, the Commission issued a Notice of Scheduling Conference to be held on August 13, 2009, to determine a revised procedural schedule for the case. On August 11, 2009, the Office filed a request to establish a schedule for rate design testimony and hearing. On August 20, 2009, the Company filed a request to establish a schedule for the rate design testimony and hearing. On August 27, 2009, the Division filed a request to either vacate the existing Phase II schedule in this proceeding and establish a schedule for rate design testimony and hearing, or for a scheduling conference. Due to scheduling conflicts, on August 27, 2009, the Commission issued an Amended Notice Hearing in which hearings scheduled for December 2, 2009, and December 3, 2009, were rescheduled to December 14, through December 17, 2009.

On September 3, 2009, the Commission issued a Notice of Scheduling Conference to be held on September 9, 2009. On September 17, 2009, the Division and the Office filed direct testimony on capital structure and cost of capital. In response to the proposals discussed during the September 9, 2009, scheduling conference, on September 21, 2009, the Commission issued an Amended Scheduling Order Changing Phase II Testimony Filing and Hearing Dates.

On October 8, 2009, the Company and the Division filed surrebuttal testimony on capital structure and cost of capital. In addition, the Division, the Office, Kroger, the Farm Bureau, UIEC, UAE, and Wal-Mart filed direct testimony on revenue requirement and cost of service issues.

On October 19, 2009, the Commission issued an Order directing the Company to file specific forecast information and workpapers associated with the Multi-State Process ("MSP"), and directing the Division, and other interested parties, to respond to the following in rebuttal testimony: 1) whether the continued use of the 2004 Stipulation terms for the development of the Utah revenue requirement in this case is in the public interest and 2) whether there are alternatives, such as the use of the Rolled-In method without the revenue requirement adjustments contained in the 2004 Stipulation terms, which would be just and reasonable in this case.

On October 22, 2009, the Division and the Office filed surrebuttal testimony on cost of capital issues. In addition, in response to the Commission's order issued October 19, 2009, the Company filed a Petition for Immediate Stay and for Reconsideration of MSP Order ("Petition"). On October 26, 2009, the Company filed a Stipulation Regarding Change in Income Tax Treatment of Repair Deductions and Basis Normalization, the Commission issued a Notice of Hearing regarding this stipulation, and the Company filed a Notice of Filing of Its 2009 Preliminary Forecast Under Seal and Request for Relief. On October 27, 2009, the Division filed a response to the Company's October 22, 2009, Petition. On October 29, 2009, the Division filed supplemental direct testimony on revenue requirement.

On November 2, 2009, the Office, UAE and UIEC filed responses to the Company's Petition and the Company filed a request for an expedited schedule for responses to its Petition. On November 3, 2009, the Commission issued an Order setting November 5, 2009, as the filing date for responses to the Company's Petition and UAE filed its response in support of the Company's Petition.

On November 9, 2009, the Commission issued an order staying its October 19, 2009, Order and the Company filed a Motion to Strike Pre-Filed Supplemental Direct Testimony of Michael J. McGarry, Sr., Matthew Croft, and Thomas C. Brill and for an Extension of Time to File Rebuttal Testimony and Request for Expedited Schedule on Motion ("Motion to Strike"). A duly noticed hearing on capital structure and rate of return was held on November 10, 2009. On November 12, 2009, the Division filed its response to the Company's Motion to Strike and the Commission issued an Order denying Request to Strike and Order Extending Filing Date of Rebuttal Testimony. In addition, rebuttal testimony on revenue requirement and cost of service was filed by the Company, the Division, the Office, Kroger, UAE, UIEC, US Mag, and Wal-Mart. On November 16, 2009, Kroger filed a Notice of Appearance of Attorneys Licensed in a Foreign State.

On November 19, 2009, the Company filed a Petition for Clarification or Reconsideration of the Commission's November 9, 2009, Order and a letter addressing communications on interjurisdictional allocation issues. On November 23, 2009, the Commission issued both an Order Approving Stipulation Regarding Change in Income Tax Treatment of Repair Deductions and Basis Normalization and an Interim Scheduling Order, and the Company filed supplemental rebuttal testimony. On November 25, 2009, the Commission issued an Order on Request for Clarification of the November 9, 2009, Order. On November 30, 2009, surrebuttal testimony was filed by the Company, the Division, the Office, UAE, and UIEC.

On December 2, 2009, the Company filed joint issue and position matrices for the revenue requirement and cost of service portions of this proceeding. On December 7, 2009, the Office filed a Motion in Limine and on December 7, 2009, UIEC filed its response to the

Office's Motion in Limine. On December 8, 2009, the Commission issued an Order Approving Stipulation Regarding Change in Income Tax Treatment of Repair Deductions And Basis Normalization. On December 7, and 8, 2009, at a duly noticed hearing, the Commission heard testimony addressing issues relating to the Company's revenue requirement request. On December 14, and 15, 2009, at a duly noticed hearing, the Commission heard testimony addressing issues relating to net power costs associated with the Company's revenue requirement. On December 16, and 17, 2009, at a duly noticed hearing, the Commission heard testimony addressing issues relating to the allocation of the revenue increase to the various rate schedules.

On January 11, 2010, post-hearing briefs were filed by the Company, the Division, the Office, UAE, Kroger, Farm Bureau, and Wal-Mart. On January 13, 2010, UIEC filed a post-hearing brief. On January 25, 2010, the Commission sent a letter to the Company regarding a suspected error in the Company's labor calculations. On January 27, 2010, the Company responded to the Commission's January 25, 2010, letter.

II. BACKGROUND

In our October 30, 2008, Order on Motion for Approval of Test Period, in Docket No. 08-035-38,[2] we ordered a procedural process for the Company's general rate cases in which identification and selection of the test period to be used in the case would be the first item for resolution prior to the submission of other material (e.g., revenue requirement information, rate

[2] Docket No. 08-035-38, "In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations."

proposals and rate schedules and tariffs). In compliance with that order, on April 16, 2009, the Company requested approval of its proposed forecasted test period, the 12 months ending December 30, 2010.

Subsequently, the Company requested, and the Commission granted, approval of a stipulation on test period proposing a forecast test period ending June 30, 2010, using 13-months average rate base. This stipulation also identifies four investments which can be addressed in future major plant additions proceedings and includes the stipulation that the Company will not file another general rate case prior to January 1, 2011. Thereafter, on June 23, 2009, the Company filed its application for a general rate increase including supporting testimony, exhibits, rates and schedules, thus beginning the statutory 240-day clock in which a rate decision must be rendered on the application.

In our August 4, 2009, Scheduling Order, we bifurcated this proceeding into two phases in concert with our resolution of a motion to bifurcate request, and in an effort to accommodate the Commission's own schedule and the workload of the Commission and parties in this docket and Docket No. 09-035-15.[3] This Scheduling Order established Phase I to set hearings to address rate of return, revenue requirement, cost of service and revenue spread in order to render a decision within the 240-day statutory time period. We established Phase II to set hearings to consider rate design proposals.

This report and order responds to the issues raised in Phase I and decides the overall revenue change granted to the Company and the spread of this change to customer

[3] Docket No. 09-035-15, "In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism."

classes. This report and order thereby completes Phase I of this proceeding. Table 1 summarizes the revenue requirement impact on the Utah jurisdiction for the Commission's decisions on cost of capital and each disputed revenue requirement issue and is presented at the end of the section on revenue requirement adjustments. Table 4 provides the spread of the approved revenue increase to rate schedules and is presented at the end of this order.

The final hearing on rate design issues is scheduled to begin April 12, 2010. The Phase II order will set rates based on the consideration of rate design proposals.

III. PROJECTED JUNE 2010 TEST-PERIOD REVENUE REQUIREMENT

A. COST OF CAPITAL

Using a projected capital structure consisting of 48.7 percent long-term debt. 0.3 percent preferred equity, and 51 percent common equity, along with costs of long-term debt of 5.98 percent and preferred equity of 5.41 percent, and an allowed rate of return on common equity of 10.6 percent, we conclude an overall rate of return of 8.34 percent is fair and reasonable.

The Company and the Division present testimony regarding their respective views of the Company's capital structure and cost of capital to be used in setting rates. The Office accepts the Company's capital structure, but differs from the Company concerning the cost of common stock or equity and, hence, the cost of capital. The Company relies upon the expert financial testimony of Mr. Williams and Dr. Hadaway. The Division relies upon the expert financial testimony of Mr. Peterson. The Office relies on the expert financial testimony of Mr. Lawton.

1. Costs of Long-term Debt and Preferred Equity

The costs of long-term debt and preferred equity are not in dispute. For the parties addressing capital costs, all agree with the Company's cost for long-term debt of 5.98 percent and cost for preferred equity of 5.41 percent. These parties, through their witnesses, conclude the Company's proposal for these elements is reasonable and may be used in calculating a revenue requirement. No other party disputes these conclusions.

2. Capital Structure

The Company and the Division differ on what constitutes a reasonable capital structure. Specifically, the Company proposes a capital structure consisting of 48.7 percent long-term debt, 0.3 percent preferred equity, and 51 percent common equity. The Office accepts this capital structure in presenting testimony on the Company's capital costs. The Division, however, argues these percentages are not reflective of what the Division views as reasonable, nor should this capital structure be used in determining a revenue requirement and setting customer rates. The Division, through its witness Mr. Peterson, proposes a capital structure of 49.2 percent long-term debt, 0.3 percent preferred equity and 50.5 percent common equity.

Both the Company's and the Division's proposed capital structures are within the range of each of these parties' comparable company groups' capital structures from which they reference some of their cost of capital testimony. The primary difference between the two recommendations is that the Company's considers a five-quarter average of the Company's capital structure assumed in adjusted budgets, while the Division's considers the Company's reported capital structure (from the June 30, 2009 SEC Form 10-Q), information contained in confidential responses to Division data requests, and the Division's estimate of net income for the last six months of 2009 (higher or lower net income being reflected in higher or lower retained earnings which correspond to a higher or lower equity component in a company's capital structure).

3. Cost of Common Equity

As in past cases, the parties' witnesses employ various financial models which are said to be predictive of the rate of return expected by investors (specifically, the Discounted Cash Flow ("DCF") model and risk premium models, including the Capital Asset Pricing Model ("CAPM")), as well as their opinions and views of financial market expectations and trends to arrive at their competing point estimates of a cost for, or necessary rate of return on, common equity. Mr. Hadaway's point estimate is 11 percent, Mr. Peterson's is 10.5 percent and Mr. Lawton's is 10.0 percent. Dr. Hadaway critiques the positions of Messrs. Peterson and Lawton and suggests had they correctly performed their analyses, they, as well as the Commission, would conclude 11 percent is an appropriate rate of return for common equity. Likewise, Messrs. Peterson and Lawton suggest how Dr. Hadaway's analyses can be corrected, or if their own analyses are used and properly considered, the Commission should adopt their individual recommendations for common equity.

The Company also presents the testimony of Mr. Williams. Mr. Williams presents a number of analyses and his opinions which are intended to lead the Commission to conclude that setting the cost of common equity different than Mr. Hadaway's recommendation (i.e., as suggested by Messrs. Peterson or Lawton) or using a capital structure different than proposed by the Company (i.e., as suggested by Mr. Peterson) will risk credit rating agencies downgrading the Company's credit rating. The Company argues such a downgrade will ultimately result in an overall higher cost of capital than otherwise would result from the use of the Company's positions. Messrs. Peterson and Lawton contend their cost of common equity recommendations do not risk any rating downgrade. Mr. Peterson further contends his capital structure recommendation will continue to support the Company's current credit rating.

Messrs. Peterson and Lawton disagree with Dr. Hadaway's DCF modeling, particularly his inputs and weighting or consideration of the results of the various applications of the DCF model. Mr. Peterson questions Dr. Hadaway's use of gross domestic product ("GDP") growth rates as an input for DCF analysis. Mr. Peterson disagrees with Dr. Hadaway's historical GDP growth rate calculation and its use as the expected growth rate for electric utilities. Mr. Peterson argues that if GDP growth rates are viewed as a proper DCF growth rate input, they should be future GDP growth rates. Mr. Peterson views future GDP growth rates as more relevant to or predictive of electric utility growth rates for the period for which the Commission is asked to set rates in this general rate case. Mr. Lawton also challenges the appropriateness of a GDP-based growth rate input used in Dr. Hadaway's DCF model analysis. He notes Dr. Hadaway gives no support for the calculation method to derive the historical average used in Dr. Hadaway's analysis. If GDP growth rates are to be used, Mr. Lawton suggests using a simple 20-year average rather than the calculation method used by Dr. Hadaway. Messrs. Peterson and Lawton also critique the growth rates used by Dr. Hadaway in his other DCF-model-based estimates and Dr. Hadaway's weighting of these estimates. Mr. Lawton argues Dr. Hadaway used sources which overstate the growth rate to be used. Mr. Lawton argues other growth rate inputs are more appropriate in conducting DCF model analyses to estimate the cost of common equity. Mr. Peterson makes similar critiques of Dr. Hadaway's alternative DCF growth rate inputs and the deductions which Dr. Hadaway makes from the DCF analyses made. In turn, Dr. Hadaway critiques Messrs. Peterson's and Lawton's alternative growth rates and differing DCF based analyses and their justifications for their use and consideration by the Commission.

Similarly, these witnesses disagree on the CAPM and other risk premium analyses and results which they present to the Commission for consideration in determining the cost of common equity. They have varying views for the risk premiums, the underlying or base cost of debt to which any risk premium is to be added, the relevance and appropriateness of the referential information from which they derive these inputs for risk premium analyses, and the weight to be given any risk premium analysis.

Messrs. Hadaway, Williams, Peterson and Lawton presented additional installments of their testimony, which, in addition to responding to other witnesses' testimony, are also represented as accounting for changes in financial markets as this general rate case progressed. This provides further points of contention between the witnesses. Based on their views of financial markets and what is transpiring therein, Messrs. Peterson and Lawton conclude capital costs are decreasing, but Dr. Hadaway claims capital costs are increasing. Concomitantly, each side criticizes the other for the 'erroneous' view of financial market expectations and trends, and for not revising their final equity cost estimates correspondingly.

4. Discussion, Findings and Conclusions

As we stated in our Report and Order issued August 11, 2008, in Docket No. 07-035-93,[4] we resolve the cost of capital disputes of the parties recognizing reasonable people may reach different conclusions on these issues. The parties have agreement only on the cost of long-term debt and preferred equity. Where the parties disagree, on capital structure and cost of common equity, their cumulative differences equate to a difference in what each views as the appropriate Company revenue requirement to be used in this case.

On the disputed element of capital structure, the parties present differing views of what the “right” proportions should be and their possible impact on the Company’s credit rating. For the cost of common equity, the parties present multiple model analyses providing a range of estimates for the cost of common equity. The parties’ witnesses disagree on why proposed input values and assumptions may or may not be appropriate. Witnesses also argue for and against the use and weighting of various iterations of a model, the aggregate consideration of all models’ results to obtain an estimate for the cost of common equity and other factors which a witness believes should be considered in making our decision.

a. Costs of Long-term Debt and Preferred Equity

We accept and adopt the parties’ position regarding the costs of long-term debt and preferred equity. We find no basis to reject these respective costs of 5.98 percent and 5.41 percent.

---

[4] Docket No. 07-035-93, “In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge.”

b. Capital Structure

We will adopt the capital structure proposed by the Company. Both the Company and the Division have presented a basis upon which one could project what the Company's capital structure will be during the rate-effective period. We choose the Company's position for the following reasons: 1) Its use of a five-quarter average versus the Division's reliance on a single point in time smooths out the variability which is inherent in the lumpy nature of equity infusions and debt issuances; 2) approving the Company's proposed rate maintains the status quo with respect to capital structure and there is insufficient evidence on the record to convince us significant changes beyond normal variability have occurred; 3) when the projected capital structure is calculated using both parties' positions for the various disputed factors, such as lease treatment and other identified errors, the range of results using the Division's method includes the Company's proposed structure and therefore there is no significant statistical difference between the two positions.

c. Cost of Common Equity

We continue to place primary reliance upon DCF model results to estimate the cost of common equity. The risk premium models also provide information which can appropriately be considered in determining the cost of common equity in this case. The parties make final point estimates ranging from 10 to 11 percent. These point estimates are made from DCF and risk premium model result ranges, referenced by witnesses, spanning from 8.55 to 12 percent, depending upon which version of a model is used and which inputs are used. At times, the parties' witnesses provide some discussion of why they do or do not place reliance upon some result, why they may or may not give some weight to a particular result (usually without disclosing their precise weighting), and reference factors which, in our view, generally indicate the area in the spectrum of model results from which they argue we should make our determination. No party has convinced us their point estimate and the method by which they ostensibly obtained their estimate is the only right determination in this record. We make our own consideration of the multiple model iterations, the possible input values to be used, and the weighting of the multiple results so obtained. Using the financial models as we deem appropriate, with the inputs or components and weighting we believe reasonable, and weighing all of the expert financial testimony received, we find and conclude that a rate of return on common equity of 10.6 percent is reasonable.

B. REVENUE REQUIREMENT ADJUSTMENTS

1. Introduction

On June 23, 2009, the Company filed direct testimony and exhibits in support of a revenue increase of approximately $66.9 million based upon a forecast test year beginning July 1, 2009, and ending June 30, 2010, using a 13-month average rate base, and a return on equity of 11.00 percent. As a consequence of the Commission's approval of two stipulations[5] the Company's requested revenue increase is $59.3 million based on the Company's rate of return proposal.

---

[5] December 8, 2009, Order Approving Stipulation Regarding Change in Income Tax Treatment of Repair Deductions and Basis Normalization in Docket Nos. 09-035-23 and 09-035-03, "In the Matter of the Division of Public Utilities' Review and Audit of Rocky Mountain Power's Deferred Tax Normalization Method."

August 25, 2009, Order Granting Approval of Phase I Stipulation, in Docket No. 08-035-T08, "In the Matter of the Approval of Rocky Mountain Power's Advice No. 09-08 Schedule 193-Demand Side Management (DSM) Cost Adjustment."

Parties recommend various adjustments to the Company's forecasted test year revenue requirement. Some of these adjustments the Company accepts and some are in dispute. We provide a list of the undisputed items, including the two stipulated amounts noted above, and a description of each disputed adjustment followed by our decision addressing the disputed issue. The disputed issues address net power costs, labor expenses, non-labor expenses and rate base. We conclude this section with a numerical summary of the approved adjustments to the Company's forecast of the Utah jurisdictional revenue requirement for the June 30, 2010, test period given our cost of capital decision.

2. Undisputed Adjustments

In rebuttal testimony, the Company makes adjustments to its direct testimony test period forecast of revenue requirement which are unopposed by any party. These adjustments change the Company's test period forecast of revenue, expense, or rate base relating to the following issues: tax settlement; special contract revenue; green tag revenue; reverse operation and maintenance budget target; salaries and wages; medical insurance; postemployment benefits FAS 112; 401(k) contributions; incremental generation operations and maintenance; environmental settlement (PERCO); deferred transmission project AFUDC/PHFFU; Bridger and Trapper Mines; plant additions; plant retirements; depreciation and amortization expense; accumulated depreciation and amortization; plant-related tax update; Demand Side Management settlement - Sacramento Municipal Utility Department revenue imputation removal; hydro logic and inputs - motoring and efficiency loss; wind integration error correction; Currant Creek, Lake

Side and Gadsby expected forced outage rates; Wyodak heat rate correction; remove McFadden Ridge Transformer double count; and net lag days in cash working capital.

We accept these adjustments with one caveat. This caveat is with respect to the adjustment proposed by the Division relating to the lead lag study. We accept this adjustment for this case only, but do not accept the method going forward because, as ratemaking policy, we believe the supporting evidence is incomplete.

Interjurisdictional allocation of test year results of system operations is performed assuming ratemaking policies are consistently applied to all jurisdictions, thereby determining jurisdictional revenue requirement in an equitable manner. The Division recommends the components of only Utah's net lag factor be updated using the adjusted test year revenue and expense components, rather than historic values. Formerly the net lag factor was independent of the adjustments necessary to create the test year. If this updating is really necessary, then this approach should be simultaneously applied to all jurisdictions, not just Utah, for reasons discussed below.

The value of this adjustment, when updating is uniformly applied to all jurisdictions, may be less than the value resulting when updating is applied to one jurisdiction only, as proposed in this case. That is, the small value associated with this adjustment may be due to the selective application of updating. There has been no evidence presented on this point.

Furthermore, cash working capital influences the value of rate base; rate base is used to determine imputed interest expense; imputed interest expense is deducted from taxable income for the purpose of calculating income taxes; and income taxes are input into the calculation of cash working capital. Thus cash working capital, interest expense and income taxes are simultaneously determined for all jurisdictions. Hence, application of this updating adjustment to a single jurisdiction as proposed by the Division becomes even more problematic. Given these interdependencies, this attempt at accuracy regarding what is inherently an imprecise number introduces more modeling complexities and difficulties, and less simplicity, understandability, and transparency.

The Commission needs evidence there is a benefit to the Division's proposal before adopting such proposal as policy. This may include a consideration of similar issues and application of similar policies in other instances.

These adjustments reduce the Company's forecast of Utah test period revenue requirement by approximately $17.207 million as shown in Table 1. Given our cost of capital decision reducing Utah's forecasted test period revenue requirement by $15.639 million, and accepting these undisputed adjustments, the Company's forecasted revenue increase at this point is $34 million.

3. Net Power Costs

Net power costs are a subset of total Company power costs and are equal to the sum of fuel costs (in Federal Energy Regulatory Commission ("FERC") accounts 501, 503 and 547) wholesale purchases (account 555) and wheeling expenses (account 565) less wholesale sales revenue (account 447). The dollars in these accounts are adjusted from actual results in order to normalize and/or forecast net power costs for the total system during the test period. To this end, the Company uses an hourly production dispatch computer model called Generation and Regulation Initiatives DecisionTool ("GRID") to simulate normal system operating conditions and forecast net power costs for the future test period in this case. All other power-related accounts are determined for the test period outside of GRID.

In direct testimony, the Company forecasts about $999 million in total system net power costs during the test period. In rebuttal testimony, the Company proposes additional adjustments supporting a forecast of $1.018 billion in system net power costs. Parties propose adjustments to the Company's forecast some of which are undisputed and included above. Parties also propose adjustments which the Company disputes and some parties dispute adjustments proposed by the Company in its rebuttal testimony. All adjustments are stated with respect to the Company's direct testimony net power cost forecast of $999 million.

a. GRID Market Capacity Limits

The Company uses hourly energy market capacity limits ("market caps") in the GRID optimization process to constrain GRID from making as many short-term firm ("STF") and spot or balancing wholesale power sales during the early morning, or graveyard, hours (1:00 am to 5:00 am PST) as allowed in all other hours. GRID makes these sales when profitable to do so, serving to reduce overall net power costs. The Company claims it is not possible in reality to make as many sales during these hours as the GRID model, unconstrained by market caps, would make, and hence maintains the need to impose tighter market caps during these time periods than during the other hours of the year. These caps are set equal to the average of 12 months of actual graveyard spot market sales in 2008.

The Company states it first proposed the caps in Utah in Docket No. 03-035-14,[6] a case set to establish an avoided cost method for certain qualifying facilities. In that case the market caps were set equal to the average of 48 months of actual graveyard spot market sales.

The Office testifies it first became aware of the Company's use of market caps in a 2003 Wyoming case which was based on an historical year. In that case, actual STF transactions were known and modeled based on the actual, historical sales. Therefore, to construct the size of the market caps, the Company only considered the amount of spot or balancing sales. The sum of the two types of transactions, STF and spot sales, in that case amounted to 3.75 million megawatt-hours in graveyard hours. In the present case which uses a forecast test period rather than an historical test period, the Office testifies the amount of STF transactions are limited to only those the Company had under contract prior to the filing date of the case, with balancing transactions making up the difference in the net power cost study. Consequently, the Office asserts "the volumes of STF transactions are substantially lower than those that occurred in prior periods and which are likely to occur in the test year as it unfolds. This is especially true for sales during graveyard shift hours."

The Office testifies graveyard sales in the Company's net power cost study, based on the market caps, amount to 1.8 million megawatt-hours. Removing the market caps, the Office's net power cost study provides 3.1 million megawatt-hours of total graveyard STF and balancing sales. The Office states both figures are far below the amount included in the 2003 Wyoming test period (3.75 million megawatt-hours) and much less than recent actual results for

[6] Docket No. 03-035-14, "In the Matter of the Application of PacifiCorp for Approval of an IRP-based Avoided Cost Methodology for QF Projects Larger than One Megawatt."

the 12 months ended June 30, 2008, (4.6 million megawatt-hours) or for the 12 months ended November 30, 2008, (5 million megawatt-hours), according to testimony filed in Wyoming.[7] Thus, the Office argues the Company's test period includes only a fraction of the ultimate level of STF and balancing sales. The Office believes the evidence shows a growing market and use of the market caps will understate the volume of graveyard sales.

To address this issue, the Office recommends eliminating the market caps for the four largest trading hubs: COB, Palo Verde, Four Corners and Mid-Columbia. This adjustment reduces the Company's system net power cost forecast by $10.9 million and provides lower graveyard STF and spot sales than recent history (3.1 million megawatt-hours modeled versus 3.75, 4.6 or 5 million megawatt-hours actual).

The Office testifies its adjustment also produces reasonable coal generation in graveyard hours (9.55 million megawatt-hours) as compared to actual coal generation in the historical base period of December 2008 (9.35 million megawatt-hours). The Office states the Company's net power cost study of coal generation during graveyard hours is 8.79 million megawatt-hours which is just slightly less than the 2003 Wyoming case. Further, the Office argues, the total coal generation in the Company's net power cost studies in the 2008 general rate case, Docket No. 08-035-38, showed 46 million megawatt-hours of coal generation, differing from the Office's net power cost study in this case (46.1 million megawatt-hours) by only a trivial amount.

[7] Direct testimony of Mark Widmer, Docket No. 20000-341-EP-09, page 13.

The Company recommends the Commission reject the Office's proposed adjustment because it will result in an unreasonably high level of coal generation and thereby understate test period system net power cost. Further, the Company argues the adjustment is contrary to the Commission's avoided cost method which adopted market caps as a means of maintaining customer neutrality.

The Company points to its rebuttal testimony in the avoided cost case, Docket No. 03-035-14, in which it argued markets are illiquid during graveyard hours when customer loads are lowest and thus its dispatchable high cost resources are backed down or shut down and some coal units are backed down. The Company now argues "market caps are still needed to limit the sizes of wholesale sales markets during graveyard hours to reflect the fact that the wholesale market is not liquid during these hours. Without the market caps, GRID would allow the Company's coal units to produce more power than can be absorbed in these markets during graveyard hours and would therefore overstate coal generation. OCS's proposal to eliminate market caps would result in GRID modeling wholesale sales during graveyard hours in amounts that overstate actual coal generation."

Disagreeing with the Office, the Company asserts actual coal generation for the historical base year ending December 31, 2008, is not the proper basis of comparison for determining whether the coal generation level modeled in GRID is reasonable. Instead, the Company contends a four-year average of historical coal generation should be used to verify the reasonableness of the amount of coal generation modeled in GRID. This is because GRID plant outages are based on a four-year average and this determines the availability of thermal units in GRID. The Company testifies the level of coal generation modeled by the Company in GRID exceeds the four-year average actual coal generation by about 125,000 megawatt-hours. The Company asserts the coal generation in the Office's final recommendation exceeds the four-year average of actual historical generation ending December 31, 2008, by 838,251 megawatt-hours. The Company argues use of the market caps is necessary to keep GRID from optimizing costs to an unreasonable level. Removing the caps increases total coal generation in the test period to 46.1 million megawatt-hours, an amount the Company argues is among the highest actual levels the Company has experienced since 2000, except for late 2007 and early 2008 when availability spiked for a short period.

The Office responds by noting the Company completely ignores the issue of wholesale sales in graveyard hours. The Office argues it is this sales data which provides evidence concerning market liquidity and the Company provides no evidence regarding this matter. The Office argues the Company's reliance on Docket No. 03-035-14 is misplaced because the Commission concluded the evidence in that case supported use of the market caps. The Office argues there is new evidence in this case to demonstrate market caps are no longer needed to constrain coal generation. The Office argues the size of the market, as measured by the Company's actual sales, is far greater than assumed in the GRID model.

Disagreeing with the Company, the Office claims a four-year rolling average of coal generation data is not a realistic metric for evaluating the reasonableness of the amount of coal fired generation in the net power cost study due to the many systematic changes which require the use of more recent data. Since the Commission's order in Docket No. 03-035-14 was issued, the Office testifies loads have grown and the Company has added Currant Creek, Lake Side, and Chehalis natural gas plants and numerous wind plants. The Office argues the new gas plants allow for increased coal-fired generation because they are now carrying reserves previously assigned to coal units. Thus, a four-year average of coal generation as a basis for determining the propriety of the market caps is unrealistic. The Office argues many other factors also impact coal generation, including the decline in hydro generation, the increase in wind generation and fuel price changes. Because so many factors vary between the test year and the four-year historical period of coal generation, data more than two years out of date is of little value. The Office argues its 46.1 million megawatt-hours of coal generation is quite reasonable compared to the 2008 actual data (46 million), the same period in which the market caps for graveyard hours was based. The Office also points to the 2008 rate case in which the Company's 2009 test periods (for both December 2008 and March 2009) showed 46 million megawatt-hours of total coal generation in the net power cost studies.

Finally, the Office argues the Company includes a substantial wind integration adjustment in this case which is computed outside of the GRID model. The Office argues the $20 million adjustment represents the cost of holding reserves on coal and gas units to provide for wind integration services. GRID does not explicitly model these reserves but the costs included in the test period accounts for them. Therefore it is not accurate to simply compare the GRID output reports to historical data. The Office reasons if the wind integration component of reserves is considered, the test period contains far less coal generation than shown on the GRID output reports. The Office quantifies the effect of including additional reserves for wind integration by including the reserves directly in GRID at a level supported by the Company's wind integration work-papers and sufficient to replicate the intra-hour wind integration cost used by the Company. When included, coal generation in the test period is reduced by more than

700,000 megawatt-hours (from 46.1 to 45.4 million megawatt-hours which differs little from the four-year historical average for coal generation (45.4 million megawatt-hours) reported by the Company.

Two issues are raised with respect to the market caps assumed by the Company. On the one hand, the Office argues the market caps cause the model to understate total graveyard sales. Not only are spot sales limited by the market caps, which are based on historical spot sales data in 2008, but STF graveyard sales are also limited because only those contracts signed prior to the Company's filing are included in GRID. The evidence in this case supports the Office's conclusion that total graveyard sales are understated.

On the other hand, the Company argues the entire point of the caps is to ensure a reasonable amount of coal generation is included in normalized net power costs. The Company does not address the issue of whether the caps are having an adverse effect on properly forecasting wholesale sales in graveyard hours.

The Office argues much has changed in the Company's utility system since the caps were adopted for use in Docket No. 03-035-14 in order to appropriately account for coal generation backdown in graveyard hours. However, we are not persuaded removal of the caps is the appropriate adjustment to better account for normalizing both coal generation and STF sales in graveyard hours. We are troubled by the lack of data in the record regarding the base year amount of STF sales volume in graveyard hours and how such sales are related to current utility system operations. Indeed, with gas generators now in the system and on the margin, and substantial wind resources impacting system dispatch, we find we require further discussion and analysis to determine the best way to ensure a reasonable, normal amount for each one of these components of net power cost is included in the test period upon which we set rates.

We will, in this case, accept the Company's use of the market caps but will require updated support in the future to determine if these caps continue to be relevant and if they are not resulting in unintended and inappropriate consequences with respect to forecasting STF sales in graveyard hours.

b. Uneconomic Model Operation

The Office argues that without user-supplied workarounds, referred to as screens, GRID frequently fails to develop the least cost sequence of start-ups and shut-downs for gas-fired resources. The Office states this occurs because the logic in GRID separates the decision to commit (to start up or shut down) a resource from the operating constraints (transmission limits and market capacity limits) in the model. These operating constraints are later used to determine the optimal dispatch of resources. Thus, GRID assumes energy produced by a generator can always be sold in markets when making the commitment decision. As a result, units run when there is no market for the energy they produce. The effect of this error is to raise power costs because it always results in suboptimal resource utilization.

To address this issue, the Office testifies the Company uses a monthly method for developing screens for combined cycle and peaking plants and monthly start-up costs. The Office testifies the Company also retains an annual screen for peaking units in addition to the latest monthly screens it is using. While the Office agrees the Company's new screening method is an improvement over methods the Company proposed in Docket No. 08-035-38, it argues this approach does not eliminate uneconomic generation in GRID and introduces new problems.

The Office explains the Company's approach relies on monthly averages rather than daily analysis. Thus, it does not identify the specific days when the cycling units should be running and fails to determine the best start-up or shut down times for each day. The Office proposes an adjustment using daily rather than monthly screens. This adjustment includes new screens for Currant Creek, Lake Side, and Gadsby and purely financial screening adjustments for the duct firing resources. The Office testifies the screens it used in Docket No. 07-035-93 and which the Commission adopted in that case, were based on an analysis of hourly cost data. The Office argues addressing the GRID logic flaw is complex and better screens could be developed but argues the screens it develops do a better job of reducing the error-induced costs than the Company's. The Office provides an exhibit showing the amount of error-induced costs which are removed from GRID is significantly higher based on use of a daily rather than monthly screening method. The Office argues since the GRID logic fault only increases net power cost, the Commission should adopt the best method available. The Office's proposed adjustment reduces total Company test period net power costs by $1.8 million and Utah revenue requirement by approximately $0.8 million.

As in the 2007 rate case, the Office testifies its adjustment is only an interim solution to be used and, if possible, improved upon until the GRID logic error itself can be fixed. In the meantime, the Office recommends the Commission require the Company to implement a minor GRID modification to export the hourly sum of fuel and purchase power costs less sales revenue to facilitate the production of screens allowing a time savings for all parties and should be required to be included in the very next power cost related case. The Company does not oppose this recommendation.

The Company applies a monthly screening method which it claims was approved in the 2007 rate case, Docket No. 07-035-93, and includes costs associated with additional start-ups required by the screens. The Company does not indicate why it has not fixed the logic error in GRID but opposes the Office's recommendation to use daily analysis to address the issue. The Company opposes the Office's daily screening method claiming it is based on faulty logic. The Company argues GRID includes several variables, namely forward price curves, loads, and resources, that do not change on a daily basis and therefore use of daily screens is unwarranted absent inclusion of the daily volatility of system and market conditions in GRID. The Company also argues the Office's adjustment is based on a mixture of GRID dispatch and "financial" adjustments that are inconsistent with the dispatch. Further, the Company argues the adjustment to the duct-firing units does not consider the fact that GRID already overstates the flexibility of these resources.

We concur with the Company and Office that an adjustment to remove the uneconomic generation produced by faulty GRID logic is necessary. We adopt the Office's adjustment in this case because of the evidence that the daily screens do a better job of reducing the uneconomic generation. It is our understanding GRID was developed in order to reflect hourly system operations as an improvement to the monthly energy production dispatch tool (PDMac) used in prior rate cases. Therefore, we are not persuaded daily screens are inconsistent with overall GRID design and therefore inappropriate for addressing this issue. We recognize GRID does not include daily volatility of system and market conditions but believe this is another issue.

We again urge the Company to fix the GRID logic error and we will continue to evaluate methods to address this issue until the logic error is fixed. We direct the Company to provide the information requested by the Office in future cases, in order to allow parties to examine this issue and propose solutions as needed. This decision reduces the Company's forecast of Utah test period revenue requirement by $0.738 million and is reflected in Table 1.

c. Start-up Fuel Energy Value

When a gas-fired generating unit begins operating after an idle period, there is a short period in which the plant is producing electricity, but has not yet reached its typical minimum operating level. This is known as the start-up period and the energy produced is the start-up energy. The Company includes fuel costs associated with the start-up of certain gas plants but does not include a value for the energy generated when the plant is starting up. Both the Division and Office propose adjustments to value the start-up energy produced since the costs of this start-up energy is included.

The Division proposes to include a credit, valued at the average price of coal energy, to account for the start-up energy at the Currant Creek, Lake Side, Hermiston and Chehalis gas plants. This method assumes the start-up energy reduces coal generation, which the Division argues is a reasonable assumption since startups generally occur in early morning hours, causing coal units to reduce output and it was suggested by the Company in the previous rate case. The Division's proposed adjustment reduces total Company net power cost by $2 million and Utah revenue requirement by approximately $0.9 million.

The Office argues it is standard industry practice for chronological power cost models like GRID to reflect start-up energy. The Office proposes to include start-up energy by modeling a start-up sequence for Currant Creek, Lake Side and Chehalis gas plants and assumes the energy produced goes into the power system, offsetting purchases, or other generation. GRID then reflects a reduction in coal generation and other resources to account for this energy. This proposed adjustment reduces total Company net power cost by $3.7 million and Utah test period revenue requirement by approximately $1.5 million.

The Company recommends the Commission reject the proposed adjustments because GRID already overstates the generation when the gas units start up and understates system costs during the start-up process. The Company argues start-up costs are not limited to fuel and these other costs are not included in GRID. Further, GRID assumes gas units will always be able to reach their full capabilities instantaneously and thus the model overstates their generation when they are still ramping up. Because there is no mid-hour market for start-up energy, the Office's approach to modeling the start-up energy is incorrect because it assumes that such energy is firm and can replace purchases and be used for sales. Also, the Company primarily uses its hydro generation to follow the ramping up of the gas plants and therefore does not save fuel by ramping down coal generation or transact in the market while gas units are ramping down with hydro generation. GRID does not account for the fact that the efficiency of other plants degrade as they are ramped down during gas plant startup. Finally, GRID does not reflect loss of energy from ramping down units while gas-fired units are ramping up. Thus, the Company argues, together with the other costs that are not modeled in GRID, there is no value that needs to be included in the net power cost study. In addition, the Company argues the Division and Office proposals violate the technical requirement of the minimum down time required for a unit to stay offline before it comes back online. In contrast to the Office, the Company argues it is standard industry practice for each utility to model its gas plant startups so as to reflect the unique design of its production dispatch model.

In response, the Office argues the Company provides no analysis or evidence regarding reserve requirements or lack of an intra-hour market. The Office argues the Company's assertion that hydro provides the reserves for combined cycle start-up energy contradicts the Company's intra-hour market and efficiency loss arguments. Further, the Office contends the Company's argument that GRID doesn't reflect the efficiency losses of other thermal plants as they ramp up when combined cycle units are starting is inconsistent with the assumption that hydro is following the ramp up of combined cycle units. Further, the Office disagrees with this point because GRID models heat rate curves for all units, generally resulting in higher heat rates as output is reduced.

While the Office agrees its modeling is not consistent with the assumed minimum down times, it argues the impact is negligible based on detailed analysis it performed using GRID. Further, the Office performed an analysis to address the Company's concern regarding the need to increase reserves to cover the ramp up of combined cycle plants, and concluded the impacts are inconsequential. Thus, the Office continues to recommend its adjustment. The Office recommends the Company's various concerns could be addressed in a future case but its adjustment has not been overstated in this proceeding for various reasons.

The Division also maintains its recommended adjustment in response to the Company's concerns. The Division states the Company is inconsistent between its direct and rebuttal testimony regarding its objections concerning start-up energy. In direct testimony, the Company opposed an adjustment because the value of such energy is expected to be small. In rebuttal, the Company objects to an adjustment because GRID overstates the generation when the gas units startup and understates system costs during the start-up process.

The Division defends its value for the start-up energy which is based in part on a data response in which the Company stated that as gas units ramp up and other units back down, they reduce their fuel input and there are resulting fuel cost savings, including cost savings from a gas unit. However, in rebuttal the Company states the energy could also lower hydro generation. The Division argues its proposed credit based on the average cost of coal is a reasonable middle ground for estimating the fuel cost savings from start-up energy.

The Division disagrees that GRID overstates generation when the gas units start up. The Division testifies that while GRID does not explicitly model unit startups and the associated start-up energy, GRID considers unit generation that occurs after the unit reaches minimum load. An input data field called Startup MMBtu is used to include the cost of start-up energy in the GRID results since it does not capture that cost through any other means. The Company uses this special field so the cost of start-up fuel is included in the GRID results and net power cost, however, the corresponding energy is ignored.

We are concerned the Division and Office proposals have not completely addressed the Company's concerns that other GRID model simplifications which contribute to an understating of the cost of start-up fuel may obviate the need to value start-up energy. We will accept the Company's explanation in this case and make no adjustment to value start-up energy. However, in the future the Company must demonstrate quantitatively that the value associated with GRID model simplifications offsets the value of start-up energy.

d. Sacramento Municipal Utility District ("SMUD") Contract Shaping

The SMUD contract is a long-term firm sales contract scheduled to expire in 2014, whereby the Company supplies SMUD with 350,400 megawatt-hours of on-peak power annually at a rate of 100 megawatts per hour. In Docket No. 07-035-93 the modeling of this contract was disputed and the Commission ordered the Company to normalize the contract cost based on a four-year average to reflect how SMUD uses the contract.

In its direct testimony, the Company asserts there is an additional component to the SMUD contract that was not addressed in Docket No. 07-035-93. The Company asserts "it turns out that the original method only looked at the firm power portion of the SMUD contract, while the contract also allows SMUD to take provisional power. When both of these are modeled together, the SMUD contract showed that the shape proposed by the Committee [Office] in the 2007 general rate [case] does not comport well with the historic take by SMUD under the contract." Therefore, the Company modeled the contract as it did prior to the Commission's decision in Docket No. 07-035-93, i.e., at maximum cost to the Company. The Company asserts for the current proceeding, the contract is optimized per the terms of the contract. Further, by reference to Docket No. 08-035-38, the Company argues treatment of this contract differs with treatment of other long-term contract modeling.

The Office testifies that under the provisional clause, SMUD has the option to take an additional 219,000 megawatt-hours at a delivery rate not to exceed 100 megawatts per hour, at any time during any given year. SMUD then must return that power at any time in the following year. The Office objects to the Company's adjustment for two reasons. "First, the Commission has never considered the provisional contract clause. This is an extremely unfavorable aspect of the SMUD contract, which heretofore, the Company has not modeled in its power costs studies in Utah, or to [the Office's] knowledge in other states. The Company has never sought rate recognition, or a prudence determination of the provisional contract deliveries or receipts in Utah. Indeed, the Company has normally ignored the provisional clause for retail rate cases."[8] The Office provides a data response from a Wyoming case which states that for ratemaking purposes, the Company always excluded the provisional energy. The Office also provides a copy of the GRID Long Term Contract Attributes from the 2007 case which demonstrates the SMUD provisional contract was excluded by the Company in its GRID study.

To address the provisional clause, the Office argues the Commission needs to make a prudence determination concerning the possible high value deliveries to SMUD and the low value returns. The Office argues the prudence of this aspect of the contract is highly questionable, has never been justified by the Company nor considered by the Commission.

The Office, once again, objects to the Company's argument that it is unfair to rely on actual data for one contract, while not other contracts. The Office notes the Company models the delivery pattern of other contracts the same as the Commission's approved method for the

---

[8] Falkenberg surrebuttal, page 22.

SMUD contract and cites examples. The Office proposes an adjustment which models the SMUD contract as ordered by the Commission in Docket No. 07-035-93. This adjustment reduces total Company net power cost by $0.5 million and the Company's requested Utah forecast test period revenue increase by approximately $0.2 million.

We accept the Office's SMUD modeling adjustment. This method develops the monthly energy for the SMUD contract based on the four-year average of actual sales without consideration of the provisional clause. At this time, we have insufficient evidence regarding the newly identified provisional clause to determine its prudence in the context of the entire treatment of the SMUD contract for ratemaking purposes. Indeed, in this very case parties have agreed and we have approved ratemaking treatment for imputing revenue to this contract and nowhere in the discussion and evaluation of that stipulation did any party discuss the impact of this provisional clause. We find no evidence in this case demonstrating the four-year average approach for normalizing the sales associated with the SMUD contract, as reviewed and approved for ratemaking in this jurisdiction, is no longer reasonable. This decision reduces the Company's forecast of Utah test period revenue requirement by $0.219 million and is reflected in Table 1.

e. Biomass Non-Generator Agreement

The Biomass contract is a high-cost qualifying facility contract signed in 1987 and set to expire in 2011. The current contract price per GRID output report, is $156 per megawatt-hour. The Office argues because of its high cost, the Company has negotiated non-generation agreements with Biomass QF for each year from 2005 - 2009. Under this arrangement, for example in 2007, Biomass produced no energy for a set period of time (April - June in 2007). In exchange, Biomass was paid an amount that represented a discount from its standard contract rate. For the Company, costs were lower than otherwise because the discount from Biomass was larger than the cost to replace the power. Biomass benefitted because it did not have to purchase expensive fuel when replacement power was available at a lower cost in the market.

The Office notes in the last rate case for which a full hearing was conducted, Docket 07-025-93, the Commission ordered the Company to include a non-generation agreement adjustment. Further, the Office notes “in the 2008 proceeding, Docket No. 08-035-38, after having filed its Direct Testimony without a Biomass QF Non-Generation adjustment, the Company ultimately incorporated such an adjustment in the modeling assumptions it used in its rebuttal testimony. In this proceeding, the Company did not include a Biomass non-generation adjustment in its GRID modeling assumptions.” The Office argues the underlying circumstances of the non-generation agreement are likely to continue and therefore recommends the Company reflect this arrangement in its normalized net power costs. The Office performed a GRID run assuming a Biomass non-generation agreement is in place for the period of April through June 2010. This adjustment reduces total Company net power cost by $0.8 million dollars.

The Company objects to the Office’s adjustment. The Company testifies it excluded the agreement from its net power cost study because it has not executed a non-generation agreement for the Biomass project that would be effective during the test period. The Company argues it would be presumptuous to include an agreement that has been based on the spread between prices for electricity and hog fuel, especially given the uncertain economic condition in the housing market and the wood product industry.

The Office disagrees including the non-generation agreement in net power cost is presumptuous because the Company has a five-year track record of engaging in such a contract and it is attractive to both parties. The Office argues this practice is a sound and prudent business management decision that benefits the Company, its customers and Biomass. The Office contends it looks equally good for 2010 as in 2009 as market prices are still forecast to be low during the relevant time period based on current forecast conditions. The Office notes the Company did not suggest it is not working on such an agreement or that there is any technical reason why it might not enter into such an agreement in 2010. The Office also notes the non-generation agreement adjustment was accepted by the Commission in the 2007 case despite the fact that the Company had not yet entered into non-generation agreements when the case was filed.

We conclude the Office's adjustment is a reasonable normalizing adjustment for the reasons stated by the Office. This decision reduces the Company's forecast of Utah test period revenue requirement by $0.321 million and is reflected in Table 1.

f. Chehalis Start-up Costs

The Company derives start-up costs for the Chehalis plant based on its Currant Creek plant. This is because the Company has limited operational data for the Chehalis plant and the Currant Creek plant is a reasonable proxy because of the similarities of the generating equipment at each plant.

The Office testifies the cost and fuel requirement per start for the Chehalis plant is excessive. The Office states the values in this proceeding exceed the inputs assumed in Docket Nos. 08-035-38 (the 2008 rate case) and 08-035-35 (Chehalis approval proceeding).[9] The Office argues the Company provides no support for the new inputs except that they are similar to the Currant Creek plant and contends the start-up energy appears substantially overstated compared to Currant Creek values. Using IRP-based inputs, the Office recommends an adjustment which reduces total Company net power cost by $0.7 million.

The Company objects to the Office's adjustment and testifies the Current Creek derived start-up costs are reasonable and include additional wear-and-tear not considered in the IRP based assumptions the Company previously used for Chehalis.

The Office maintains its recommendation for an adjustment because it argues the new inputs used by the Company are unsupported by any form of documentation, data or analysis.

As the Chehalis plant has limited operational data, we will accept use of the Currant Creek derived data for this case as a reasonable proxy at this time. In the next power cost case, we direct the Company to provide documentation supporting any Chehalis start-up assumptions and to provide a detailed explanation comparing these assumptions to those used in the Chehalis approval proceeding, Docket No. 08-035-35.

---

[9] Docket No. 08-035-35, "In the Matter of the Request of Rocky Mountain Power for a Waiver of the Solicitation Process and for Approval of Significant Energy Resource Decision."

g. Short Term Firm Transmission Test Year Synchronization

The Company uses four year average transfer volumes (2005-2008) to determine the STF transmission capacity limits in GRID but includes STF transmission cost (also referred to as STF "wheeling" cost) based on one year of actual data for the period ending December 31, 2008. The Office objects to the inconsistency between the modeling of capacity based on the average of four years of history but using transmission costs based on just one year. The Office testifies this approach pairs higher costs in 2008 with lower four-year average energy transfers.

The Office argues the choice of whether to use a single year rather than multi-year average is less important than having consistency between the capacity, energy flows and costs of the STF transmission links modeled. The Office provides a graph of historical data showing both the costs and volumes of STF transmission have increased substantially in recent years. In comparison, the June 30, 2010, test period volumes shown in the graph are relatively low and costs relatively high. The Office also argues the Company's STF transmission modeling is flawed. The Office maintains the purpose of STF transmission is to enable economic operation of the system, yet in the Company's GRID study, STF transmission is an uneconomic resource, incurring $0.3 million more in costs than savings through use of STF transmission. The Office proposes an adjustment which models the cost of transfers based on the four-year average volumes, the same as non-firm transmission is modeled by the Company. This adjustment reduces total Company net power cost by $4.1 million.

The Company objects to the Office's adjustment. The Company argues it is inconsistent with how other wheeling expenses are included in net power cost. The Company uses the four-year average availability of STF transmission because it varies from year to year but uses the most recent year of expense to capture the most recent costs associated with acquiring transmission from third-party transmission providers. The Company also testifies the Office uses a variable charge (dollar per megawatt-hour) to compute these expenses in GRID, and testifies this is inconsistent with STF wheeling expenses which are incurred on a take-or-pay basis. The Company argues this error results in significantly understating STF transmission expense. The Company notes the Office does not contest the prudence of the expenses.

In response to the Company's rebuttal, the Office performed an analysis using only 2008 actual expenses coupled with the 2008 transfer limits, based on actual 2008 flows. This approach still synchronizes STF transmission expenses and volumes and eliminates the Company's concern regarding use of a variable charge. This adjustment reduces total Company net power cost by $3.9 million. The Office is indifferent to the method selected by the Commission but maintains STF volumes and cost should be modeled on a consistent basis.

We accept the Company's modeling of STF transmission in this case and direct further study of this issue for the next case. The Office has raised some important issues but we find too many unanswered questions in this record to resolve the issue in this case. Our understanding of the purpose of correctly defining inputs for GRID is to forecast for the future test period the various components of net power cost, in this case STF wheeling expense. From the record it is not clear how STF transmission expense is included in the model. It appears the STF transmission expense may be a fixed input as the amount modeled or forecasted by the Company to occur in the test period 2010 is exactly the same amount as in the base historical period 2008; it does not appear this amount is the result of a simulation of operations based on a four-year average of STF transmission capability. While the Office's graph of historical volumes and expenses implies an operational link between volumes and cost, the test period amount does not appear to follow this link.

Rather than speculate further, we direct the Company to provide support in the future regarding how STF transmission cost and capability is modeled in GRID. For example, the Company must explain how all wheeling expense is treated in GRID, why it is treated in the model rather than outside the model which is the way wheeling revenue is treated. The Company must propose the best way to reflect wheeling expense and revenues in a forecast test period. We direct the Company to fully explain the interdependencies between transmission modeling and other net power cost components. Further, we require a full discussion regarding the distinctions between the modeling of non-firm, STF and other wheeling transactions which the Company and Office reference but do not completely discuss. A decision to improve upon the modeling or forecasting of STF transmission capacity and cost to best represent normal conditions in a future test period will need to consider all of these issues.

h. Transmission Imbalance

The Company does not include the transmission imbalance adjustment ordered by the Commission in the 2007 rate case in its net power cost study in the present case. It is the Company's understanding the Commission adopted the transmission imbalance adjustment in that case because the Company provided no rebuttal. The Company now states it has provided significant evidence opposing the adjustment in the 2008 rate case, Docket No. 08-035-38, and incorporates those arguments by reference in this case.

The Company testifies that, as the transmission system operator, it covers the deviation between the scheduled generation and actual generation of third parties within the control area. These deviations occur within the hour when there is no market for transactions to cover these imbalances. The Company argues the amount of energy purchased or sold is not known to the Company until after the hour when power schedules and actual generation can be compared to determine whether the Company received or supplied power.

To cover the imbalances, the Company either backs down its own generation or provides additional energy. The Company supplies this transmission imbalance service to third parties in the region at its FERC approved Open Access Transmission Tariff ("OATT") rate. The Company charges third party transmission customers when their load resource balances differ from scheduled amounts. Likewise the Company pays such fees when it is out of balance on a third party transmission provider's system. It charges a premium for the sales of the service and a discount for purchases of this service to discourage imbalances. The Company argues it does not benefit from the premiums or discounts because when it gets paid or pays these fees it is only compensation for the cost of providing the service. Thus, the premium or discount is intended to be an incentive for the third parties to minimize the imbalances, rather than a benefit or economic gain to the Company, which is the underlying assumption in the methodology ordered by the Commission in Docket No. 07-035-93. The Company states, "As long as the imbalance energy tariff is based on the market price index rather than incremental and decremental generation price, the Company will not benefit from providing imbalance services."

The Office argues imbalances are a below market source of energy for the Company because it is out of balance less often than its transmission service customers. The Office testifies the Company benefits whether there is a positive or negative balance and the ultimate impact is financial. The Office claims its adjustment is a purely financial adjustment because the impact to the Company is purely financial. The Office modifies this adjustment from the method it used in Docket No. 07-035-93 in order to address past criticisms. For example, the Office eliminates the transmission imbalances due to OATT customers as those charges are not retained by the Company, and applies the adjustment only to legacy contract customers. Further, the Office uses a 5 percent rather than 10 percent discount or markup. The Office maintains the adjustment is reasonable and maintains the Company's arguments lack analysis and essentially go to the level of the adjustment, rather than whether it should be applied. The Office's adjustment reduces total Company net power cost by $0.7 million.

Given the explanations provided by the Company in this case and Docket No. 08-035-38, we accept the Company's exclusion of the transmission imbalance service adjustment. However, we note two factors raised by the Company that will need to be addressed in the next case addressing power costs. The first is the assumption of no intra-hour markets for power. We understand this issue is evolving and direct the Company to explain how the existence of such a market will impact the transmission imbalance issue. Second, we direct the Company to explain and demonstrate that basing the imbalance energy tariff on the market price index is better for retail rate payers than incremental and decremental generation price.

i. Cholla Capacity Upgrade

The Office testifies that the Company recently upgraded the capacity of Cholla Unit 4 and this upgrade is not reflected in GRID because the Company has a firm transmission capacity limit. However, the Office argues the transmission limits are moot about 80 percent of the time because Cholla is already derated in GRID for outages. Further, STF and non-firm transmission allow some additional transfer for Cholla. The Office argues that because the derates are already counted in the forced outage rate modeling, the artificial limit on Cholla's capacity is a "double count." The Office proposes an adjustment which treats the transmission limit as a capacity deration that applies only when the unit is otherwise fully available. This adjustment reduces total Company net power cost by $0.3 million.

The Company objects to the Office's adjustment maintaining it: 1) ignores the physical transmission constraints on delivery of power from Cholla, 2) the Office's expected value mathematics is flawed because it assumes deliveries from Cholla can exceed the physical transmission available, 3) the Office increases wheeling capacity without increasing wheeling expenses, and 4) the purpose of derating the units for forced outages is to capture the lost generation due to outages. The Company argues this adjustment understates the impact of forced outages and understates net power cost.

We accept the Company's modeling of Cholla for the reasons stated by the Company.

j. Wind Integration Charges

In its direct testimony, the Company states it has updated its wind integration charges resulting in an increase to net power costs. The Company testifies there are two categories of wind integration charges. One category addresses the Company's wind resources located in Bonneville Power Administration's ("BPA") control area. The other category addresses wind resources located in the Company's control area. For the wind resources in BPA's control area, the charge is updated from $0.68 per kilowatt-month to $2.72 per kilowatt-month which is about $9.07 per megawatt-hour assuming a 30 percent capacity factor for the wind resource. Two wind projects, Leaning Juniper and Goodnoe Hills, are assessed the BPA wind integration charge.

All the remaining wind resources are in the Company's control area and are assessed the Company's wind integration charge. The Company calculates this charge using the method it developed in its 2008 IRP which derives a cost of integrating wind resources on a day-ahead, hour ahead and intra-hour scheduling basis. For this charge, the Company uses the same assumptions and method as in its 2008 Integrated Resource Plan but uses the data applicable to the test period, and calculates that the costs incurred for wind integration is $6.91 per megawatt-hour for the test period of 12 months ending June 2010. The Company calculates wind integration costs for all resources in the test period by multiplying the amount of energy associated with the wind resources by the wind integration rate and this is added to total net power cost. The total wind integration cost in the Company's direct case is around $28 million.

In rebuttal, the Company accepts two changes the Office proposes in direct testimony. First, it updates the BPA wind integration charge since the final decision on this charge was made known by BPA in July 2009. BPA approved $1.29 per kilowatt-month rather than its proposed rate of $2.72 per kilowatt-month. The Company calculates that the update of the BPA wind integration charge reduces total Company net power cost by about $1.5 million rather than the Office's calculation of $2.5 million. This is because the Company's calculation includes an adjustment to incorporate the inter-hour wind integration costs for the two wind projects that are located in BPA's control area since BPA's wind integration charge does not include day-ahead and hour-ahead balancing costs for wind. In surrebuttal the Office withdraws its $2.5 million adjustment because of its policy decision not to support any updates in which the event occurred after the Company's filing date.

Second, the Company corrects an error in its wind integration calculation identified by the Office. The Office discovered the Company overstates the amount of wind energy on the West side of the system and calculates a weighted average system wind integration cost based on this misstatement of energy. The Office revises the weighting factors based on the Company's test period net power cost study amounts of wind energy. Using the revised weighting factors, the corrected system wind integration charge is reduced from $6.91 per megawatt-hour to $6.62 per megawatt-hour. The Office and Company calculate the wind integration error reduces total Company net power cost by $1.2 million and this adjustment is referred to in the joint position matrix as an undisputed adjustment which is included earlier in this order.

In direct, rebuttal and surrebuttal testimony, both the Division and UAE oppose the Company's wind integration charges. UAE testifies the Company's estimate of self-supplied wind integration charges increased from $1.16 per megawatt-hour proposed in the previous case, to $6.91 per megawatt-hour proposed in this case, an increase of nearly 500 percent. The proposed recovery of charges increased from $6.1 million to $28 million. UAE argues a portion of the increase is due to a greater amount of wind resources being integrated into the system and a portion is attributable to an increase in BPA charges. However, UAE argues the most of the increase is due to the proposed increase in the charge for self-supplied wind integration service. UAE argues the Company has not met its burden of proof to justify the nearly six-fold increase in cost to integrate wind energy.

UAE specifically contests the Company's method for estimating the cost of inter-hour integration. UAE states the Company assumes all inter-hour wind integration occurs through market sales and purchases rather than from its own resources. Moreover, UAE contends the Company's method assumes the Company loses financially on each and every transaction. UAE argues the Company's assumption is faulty because it fails to consider Company-owned reserves in its analysis of wind integration costs. UAE states the Company's intra-hour analysis calls for massive amounts of Company-owned generation to be held in reserve to support intra-hour deviations in wind generation. Thus, UAE recommends the Company's wind integration charges be reduced by $2.09 per megawatt-hour to remove the cost of assumed transactional losses for performing inter-hour wind integration. Further, UAE recommends the Commission approve recovery of prudently incurred incremental costs associated with regulating up but allow no additional recovery of costs claimed for regulating down because these costs would represent over-recovery. This change reduces the intra-hour integration charge from $4.83 per megawatt-hour to $3.02 per megawatt-hour. The combined impact of UAE's two adjustments reduces the Company's recommended $6.91 per megawatt-hour to $3.02 per megawatt-hour. The net impact of this proposed adjustment is to reduce test period forecast of net power cost by $15.9 million.

The Division also objects to the Company's wind integration costs. The Division argues the Company's intra-hour charges are based on a seriously flawed method and the Company has failed to address the flaw and provides analysis demonstrating the flaw. Therefore, the Division does not support the Company's intra-hour wind integration charge. In surrebuttal, the Division proposes a compromise position which takes an average of all four, non-zero, intra-hour wind integration charges proposed in this case, which is about $3.00 per megawatt-hour and which is also close to UAE's recommended charge of $3.02 per megawatt-hour. Adding the inter-hour and intra-hour values, $1.79 and $3.02 per megawatt-hour respectively, yields a total wind integration charge of $4.81 per megawatt-hour. This reduces total Company wind integration cost by about $8.6 million or about $3.5 million for Utah.

We recognize the Company has limited experience in forecasting wind integration costs as the Company adds greater amounts of wind resource to its system. While we recognize the concerns raised with the Company's method, we will accept the values produced from the study in this case, as corrected by the Office's weighting factors and BPA's final decision on wind integration charge. Although the method may be new and unproven and require additional refinement, the value of $6.62 per megawatt-hour appears to be in the range of the many studies referenced in the record.

We also direct the Company to enhance its wind integration methodology to address the issues raised and noted above by the Division and UAE. The Office also provides a description of further work that should be undertaken to improve the confidence regulators have in the Company's method. We direct the Company to address all these issues in the next proceeding addressing wind integration cost issues. Additionally, we recognize markets are changing and the Company is exploring the use of intra-hour markets. We expect the method for forecasting wind integration costs for the purposes of ratemaking will improve as more experience is gained and the market adapts to integrate wind as efficiently and economically as possible. Therefore we accept the adjustments to the Company's direct case noted above for wind integration charges in this case and invite continued discussion and further proposals from interested parties on the best way to calculate, forecast and reflect in rates, the costs of wind integration. This decision reduces the Company's forecast of Utah test period revenue requirement by $0.613 million and is reflected in Table 1.

k. Stateline and Long Hollow Wind Integration Cost

The Office raises an additional issue with respect to the Company's wind integration cost in this case. The Office testifies Long Hollow and Stateline wind resources are located in the Company's service territory. These resources belong to transmission customers of the Company who supply wind energy to other utility companies. The Company provides transmission service to these customers under the Company's FERC-approved OATT. This OATT allows the Company to recover the costs of providing operating reserves but not for the cost of providing wind integration services. The Office states the Company provides wind integration service to these wholesale customers but receives no revenue from them for the wind integration service. Thus, retail customers pay for this service but receive no benefit. The Office states the Company has added $2.2 million to total Company net power cost to account for supplying wind integration services to Long Hollow and recommends this amount be removed from the test period. The Office proposes the cost associated with a portion of the Stateline wind integration cost also be disallowed, reducing total Company net power cost by another $1.1 million.

The Company responds by noting it does not have a FERC approved rate to charge these entities and therefore objects to the Office's adjustments.

We understand the marketplace for addressing ancillary services for wind integration is evolving. We accept for this case that the Company does not have a FERC approved tariff in place now to address this issue. However, we direct the Company to address this issue prior to its next rate request to avoid the risk of a cost disallowance.

l. Planned Outage Schedule

Planned outages occur when generators are taken out of service for routine scheduled repairs and maintenance. Rather than use the actual generator maintenance schedule for a given year, the Company uses a "normalized" schedule, with outage durations based on a four-year average.

Both the Division and Office propose adjustments to the Company's planned outage schedule in GRID in order to better reflect historic practices. The Division manually adjusts the planned outage schedule for coal units in GRID to more closely align the planned schedule with the four-year average of historical planned outages and provides a graph showing the monthly distribution of actual and modeled planned outages. This adjustment reduces total Company net power cost by $0.3 million.

The Office supports the Division's adjustment and its method for evaluating and proposing the adjustment. The Office also proposes a change to the gas plant planned outage schedule. The Office assumes a spring outage for Currant Creek rather than fall. Although the Office notes historical data is not yet available for a full four years of history to guide this analysis, it is more economic to perform the outage in spring and Currant Creek was assumed to have a spring outage in Docket No. 07-035-93 and the supporting facts are still valid. The Office's adjustment for the gas plant planned outage schedule also reduces the forecast of total Company net power costs by $0.3 million.

In rebuttal testimony, the Company disagrees with any adjustment and argues the adjustments proposed are arbitrary. The Company performs a "tree analysis" for developing a planned outage schedule which it argues is transparent and not subject to gaming. While the Company agrees moving Currant Creek to a spring outage is more economic, it argues operational and contractual constraints, as well as normalized modeling requirements, prevent the Company from maintaining all units in the spring. In fact, the Company states it just conducted maintenance on Currant Creek in October, 2009. The Company argues based on the relatively small size of the proposed adjustments by the Division and Office, there is no compelling reason to claim the tree structure approach is unreasonable.

We are persuaded by the Division, its planned outage schedule best normalizes planned outages to reflect actual historic practice. Since it is based on history, we find the Division's approach for defining the planned outage schedule reasonably transparent and not arbitrary. We accept the Company's explanation regarding the gas plant planned outage schedule. In this case, inadequate historical data is available to define average practice and we find the Company's explanation for the Currant Creek planned outage reasonable in this case. This decision reduces the Company's forecast of Utah test period revenue requirement by $0.141 million and is reflected in Table 1.

m. Bridger Ramping

The Company has added a ramping adjustment to net power cost to account for decreased availability when coal-fired generating units are started up. The Company has 26 coal-fired units, of which the Company has minor ownership shares in six. With the exception of those six units, the Company calculates ramping losses using the same methodology for all remaining 20 units which includes the four Jim Bridger ("Bridger") units.

The Office recommends removing the ramping loss adjustment for Bridger because there are no generator logs available for the Company's share of these units to determine actual ramping losses. Further, the Office argues review of supporting data shows that when the ramping losses are assumed to occur, reserves are being allocated to Bridger. The Office also notes the Company's share of plant output varies substantially from hour to hour and argues this demonstrates that either the data is unreliable or the allocation of generation is not constant. In either case, the Office argues, the Company lacks reasonable data upon which to compute Bridger ramping losses. The Office proposes an adjustment which removes the ramping loss adjustment for Bridger and decreases the test period forecast of total Company net power cost by $0.3 million.

The Company opposes the Office's adjustment claiming it has provided sufficient support for the data it used to calculate ramping losses, and the losses at the Bridger units are determined the same way as other coal-fired units. The Company asserts the Office's adjustment is the same as assuming that the Bridger units can go from zero to full generation instantly which is technically impossible for coal generating units.

The Office disagrees with the Company's argument that since a ramping adjustment is used for most of the Company's coal plants it should be used for Bridger as well. The Office argues that the Company acknowledges that for the six other jointly owned plants the Company does not make any ramping adjustment to outage rates. This, the Office argues, is because the Company has difficulties in obtaining the necessary unit data for jointly owned plants. For example, the Company also lacks hourly logs for Colstrip and makes no Colstrip ramping adjustment. For the same reasons, the Bridger ramping adjustment should not be implemented, so that it is treated the same as all of the other jointly owned plants

We accept the Company's ramping loss adjustment for the reasons stated by the Company.

n. Minimum Loading Deration and Heat Rate Modeling

In order to account for forced outages, the Company uses the deration method in GRID, which essentially reduces the amount of capacity of each generating unit by the expected forced outage rate.

The Office argues the deration method is a common technique to account for forced outages in production cost modeling but that GRID has a flaw in the way it models capacity derations. GRID only derates the maximum capacity of the unit by its availability rate, but does not derate the other capacity segments, such as the minimum capacity segment. In the Company's method, maximum capacity is derated by 20 percent, minimum capacity by zero percent and dispatchable capacity by 27 percent. The Office proposes an adjustment which derates maximum, minimum and dispatchable capacity by 20 percent which is necessary to properly compute generation for units when they are dispatched at minimum capacity. Unless this adjustment is made, the Office argues, the unit's minimum capacity could exceed its maximum capacity and produce unreasonable results. The Office found this event occurred in this case and in several prior cases.

Similarly, the Office testifies, an issue arises with respect to the heat rate curve used to account for the efficiency of the generating unit. Normally, each unit capacity point is associated with a unique point on the heat rate curve. When capacity segments are derated, an adjustment must be made to the heat rate curve so that the proper heat rate is still associated with the derated capacity. If an adjustment is made to derate the capacity of a generating unit, but no corresponding adjustment is made to the heat rate curve, then the wrong heat rate will be used for modeling purposes as is the case in GRID. The Office proposes to adjust the heat rate curve to eliminate the artificial and incorrect heat rate degradation built into GRID's modeling of forced outages, but does not eliminate the heat rate degradation resulting from partial outages. Making these corrections to the Company's direct testimony net power cost study, the Office's adjustments for minimum loading deration and heat rate modeling reduce the forecast of total Company net power costs by $2.8 million.

The Company opposes the Office's derate adjustments and argues they understate the heat rates because they are applied incorrectly. The Company argues the Office's approach alters thermal plant heat rate curves to artificially increase plant efficiency as compared with heat rate curves developed from actual plant operating data. Further, the Office's adjustment reduces thermal plant minimum generation levels so GRID can run thermal units at levels that are physically impossible. The Company argues changing the heat rate curve or the minimum generation level can lead to unintended consequences.

The Company provides an exhibit showing heat rate curves for a coal-fired unit and a gas-fired unit and compares methods demonstrating that the heat rate input required for various levels of generation is understated using the derate-adjusted heat rate. Overlaying the heat rate curves, the Company shows the distribution of hourly generation as produced in the Company's net power cost study. The exhibit shows many hours of dispatch below the derated maximum capacity in which the Office's proposal will understate the heat rate and therefore understate net power cost. Further, the Company argues it is not realistic to derate the minimum generation level of a unit for forced outages because the minimum level is based on the unit's technical specification below which it cannot operate. Reducing the minimum level of units below technical capacity increases the operating range of each unit and incorrectly reduces net power cost.

The Office disagrees with the Company's conclusion that when units are running below full load, the adjusted heat rate curve will be incorrect. The Office argues that 74 percent of all fuel costs in GRID are generated by units running at the maximum derated capacity. The Office disagrees its approach understates heat rates and argues its direct testimony exhibit shows that the actual heat rate at the actual minimum, maximum and midpoint capacity for each Company unit is exactly equal to the adjusted heat rate at the corresponding derated minimum, maximum and mid-point capacities. The Office disagrees with the Company's contention that any comparison to actual heat rates should be discounted for gas plants. The Office argues its adjustment clearly does a better job of simulating gas plant heat rates than the Company method and since these are the units which cycle up and down and run more hours between minimum and maximum loading they provide the best test of the methodology.

We find this issue continues to warrant further investigation prior to making any adjustments to the Company's modeling. We have concerns with both approaches but will again accept the Company's approach in this case. We direct the Company, Division and other interested parties to review alternatives for addressing this issue, review actual operations in comparison to modeling predictions, and to understand the extent of the issue. For example, one alternative could be proportionally adjusting or compressing the heat rate curves so when a plant is running at its full derated capacity it will have a heat rate associated with the non-derated full capacity, and when it is running at its minimum capacity the heat rate will be the non-adjusted minimum one.

o. High Plains and McFadden Ridge Wind Start Dates

In GRID, the Company assumes the High Plains and McFadden Wind Projects are placed into service on October 15, 2009. In a data response to the Division, the Company states the High Plains Wind Project was place in service on September 13, 2009, and the McFadden Ridge Wind Project was placed in service on September 30, 2009. In response to this inquiry and response, the Division created a new GRID scenario changing the estimated inception dates to the actual inception dates for these two facilities and proposes this adjustment in its direct testimony. This adjustment reduces the forecast of total Company net power cost by $0.5 million.

In rebuttal, the Company opposes adjustments by parties which it characterizes as updates, arguing they are one-sided and selected to reduce net power cost. The Company believes the Commission should either allow complete and symmetrical net power cost updates or exclude updates altogether. In this case, the Company recommends the Commission establish a clear timeline allowing net power cost updates based on information that is available as of the time intervening parties filed direct testimony. If this approach is adopted, the Company supports the Division's adjustment as it meets this criteria, but proposes additional updates it argues also meet this criteria.

In surrebuttal, and in its post-hearing brief, the Office argues the Company's rebuttal updates are incomplete, asymmetrical and should not be allowed at all. The Office requests the Commission decline to consider evidence offered by any party in pre-filed written testimony, in oral summaries, or in oral reply or responsive testimony, consisting of or relying upon net power cost updates offered by the Company, UAE, or Division.

The Office provides evidence of additional updates which were available prior to the due date of intervenor direct testimony which reduce net power cost yet were excluded from the Company's list of updates. The Office argues any hard and fast rule this late in the process should not be adopted by the Commission. Rather, the Commission should re-affirm the precedent it established in Docket No. 07-035-93, denying the post filing updates. The Office contends that as in Docket No. 07-035-93, the Commission will find the proposed net power cost updates in the present case are not timely and not well supported. They come late in the process and do not pass the high standard of general reasonableness, consistency and appropriate matching of costs and revenues. The Office requests that the Commission decline to consider them.

We recognize some parties would like a hard and fast rule regarding the updating or correcting of information contained in the Company's direct case requesting a revenue increase. The issue is particularly difficult when use of a future test period is selected rather than an historical period with known and measurable changes. By its very definition, a future test period is based on a combination of assumed and forecasted information in addition to known information. We will continue to apply a case by case approach for considering what are referred to as updates or corrections, and consider arguments as to what constitutes the best available information for use in a future test period. We will also consider the complexity of suggested changes in addition to the timeliness of changes. As we resolve issues, we will articulate the key considerations in determining our decision in order to provide guidance to parties in future cases.

With respect to the correction of the in-service dates for the wind projects proposed by the Division, we accept the new information and the Division's adjustment. First, it is the Division's job to verify and support or rebut the various inputs in the Company's direct case. It must perform inquiries to ascertain whether the assumptions, estimates and forecasts used by the Company in its direct case are reasonable or if not, to provide the Commission with better values and argument supporting adoption of the new values. In this case, the Division inquired and discovered better information was available regarding the in-service dates of the wind projects, it calculated the cost difference and made this proposal in its direct testimony giving ample opportunity for rebuttal and further discovery by other parties. In addition, this adjustment is fairly uncomplicated so further review could be reasonably undertaken in the time left in this case. For the foregoing reasons, we accept the Division's adjustment. This decision reduces the Company's forecast of Utah test period revenue requirement by $0.198 million and is reflected in Table 1.

p. Forward Price Curves

In its direct testimony, UAE argues the Company's latest forward price curve dated June 30, 2009, should be used in the Company's net power cost study rather than the Company's March 31, 2009, forward price curve it used in direct testimony. UAE argues it should be used because it is the Company's latest forecast and it reduces net power cost. This adjustment reduces the Company's test period forecast of net power cost by $5.3 million.

In rebuttal, the Company argues UAE has not carried through its forward price curve impacts on other adjustments and corrects UAE's adjustment for the omitted impacts. The correction reduces the Company's test period forecast of net power cost by $1.7 million rather than $5.3 million. The Company also argues other updates known at the time of intervenor direct testimony was filed should be included if the new forward price curve is to be used. The Company quantifies other impacts associated with adoption of the new forward price curve for consideration. No other party provides rebuttal testimony regarding the relative propriety of either the June or March forward price curves.

In surrebuttal, the Office opposes this adjustment arguing it has not been carried completely through to other adjustments. For example, the Office argues the wind integration charges requested by the Company are a function of the forward price curve; if the forward price curve drops, then the cost of providing reserves for wind projects decreases as well. The Office estimates such an adjustment would reduce total Company forecast net power cost of about $5 million.

In surrebuttal, UAE accepts the Company's correction to the adjustment and supports the $1.7 million reduction to total Company test period net power cost.

While we find UAE's proposed change to the forward price curve in its direct testimony timely, as it provided ample opportunity for support or rebuttal by other parties, we find it is not well supported. Changes by any party to forecast assumptions are subject to a higher standard of review than say correcting an online date or contract price. The regulatory "known and measurable" standard of review can not be readily applied to forecasts used for modeling inputs. For example, we would need to understand why the new forecast provides a better estimate of costs in the test period and how use of the new values would affect all other components of the Company's filing. We do not see such support in this record. In this case we do not even have a definition of what is meant by the "forward price curve." Nowhere is there a discussion of whether this includes natural gas and wholesale power prices or only wholesale power prices, nor are the initial or proposed values provided in the record let alone any cursory reasonableness check with alternative forecasts of market prices. It would also be helpful to have other parties comment on the competing price forecasts yet, for example, the Division is silent with respect to this issue. For the foregoing reasons, we will accept the Company's forward price curve used in its direct case.

q. Qualifying Facility Contracts

The Company models Kennecott and US Magnesium Qualifying Facility ("QF") contracts for only one half of the test period. The Division argues in its direct testimony the Company has reached agreement over the contract terms, including energy prices and associated line loss factors through the period ending December 31, 2010. These agreements will be heard by the Commission in early November. The Division testifies the Tesoro QF contract will be filed in early October 2009. The Division expects the Commission will issue an order on all three contracts prior to the end of 2009 and well in advance of February 18, 2010, which marks the end of the 240 day clock for this rate case. Further, the Commission approved a similar adjustment for the Tesoro contract in Docket No. 07-035-93. The Division calculates annualizing these contracts through the test period increases the total Company net power cost test period forecast by about $1.2 million.

In rebuttal testimony, the Company supports this adjustment in the context of other adjustments it argues also meet similar criteria for updating. In surrebuttal, the Office did not directly address these contracts but recommends the Commission deny all updates based on events that occurred after the Company's filing date which in this case is June 23, 2009, for the reasons stated earlier.

We accept the Division's adjustment as it was provided in direct testimony and includes the best available information for the test period. This decision increases the Company's Utah forecast test period revenue requirement by $0.485 million and is reflected in Table 1.

r. BPA Peaking and Grant County Contracts

In direct testimony, the Company identifies changes to these two contracts and provides estimates of the expected price changes. In rebuttal, the Company notes the actual price changes became known in September 2009 and that this new information was provided in data responses to parties at that time. However, no party proposed updating the contract prices in direct testimony. This adjustment raises total Company test period forecast of net power cost by about $8 million. About $7.9 million of this is for the BPA Peaking contract.

In surrebuttal, the Office did not directly address these contracts but recommends the Commission deny all updates based on events that occurred after the Company's filing date which in this case is June 23, 2009. In surrebuttal, UAE supports this Company update unless it is inconsistent with the Commission's policy for allowing a party to correct omitted or inaccurate information from its own direct testimony that inures to its benefit. No other party comments on the Company's proposed adjustments.

We concur with the Company, in order to use the best information available, and to be consistent, the updated contract prices for the BPA peaking contract and the Grant County contract should be accepted in this case. It does not appear information was omitted in direct testimony, rather that the Company estimated a different value which can now be corrected. The fact that the Company called out these changes in its direct testimony and the Company provides evidence that discovery on these changes was performed and made available prior to the filing date of intervenor direct testimony ensures parties had opportunity to validate, rebut or support these changes. This decision increases the Company's forecast of Utah test period revenue requirement by $3.342 million and is reflected in Table 1.

s. US Magnesium Reserves and Kennecott Generation Incentives

In its direct testimony the Division proposes to reflect additional revenue in the Company's test period forecast associated with the Company's most recent service agreement with "Company B." In rebuttal, the Company agrees to this adjustment [11.2] if the revenue is applied only for the last six months of the test period. Further, the Company proposes to adjust the revenue for three other special contract rate changes effective January 1, 2010. In surrebuttal, the Division accepts the Company's revised adjustment which is included in undisputed adjustments above reducing the Company's Utah test period forecast by about $2.2 million.

In rebuttal, the Company also argues net power cost should reflect MagCorp [sic] reserves as well as the Kennecott generation incentives that are part of the new agreements. Including these two contracts increases the forecast of total Company net power cost by $1.0 million.

In surrebuttal, the Office did not directly address these contracts but recommends the Commission deny all updates based on events that occurred after the Company's filing date which in this case is June 23, 2009, for the reasons stated earlier. No other party comments on this proposed adjustment.

We accept this adjustment based on the Company's unrebutted representation other conditions affecting net power costs were included in these special contracts which were not raised by the Division in its initial recommendations. This decision increases the Company's forecast of Utah test period revenue requirement by $0.427 million and is reflected in Table 1.

t. Idaho Power Company and BPA Wheeling Contracts

The Company identifies in its direct testimony increased expenses related to the expiration of a low priced formula power transfer wheeling contract with BPA which will be converted to a higher priced BPA point to point contract. Also the Company received a notice from Idaho Power Company ("IPC") to modify the wheeling contract associated with delivering generation from the Jim Bridger plant to the Company's load areas. At hearing the Company clarifies this wheeling contract is the Restated Transmission Service Agreement ("RTSA"). The Company testifies the RTSA wheeling contract is estimated to increase by $2 million. The total change in wheeling expense identified in direct testimony is approximately $12 million for total Company net power cost. No other party commented on the proposed changes in direct testimony.

In rebuttal, the Company proposes to increase this adjustment by $11.1 million to reflect changes in the Company's wheeling contracts with IPC and BPA that occurred as of early September. At hearing the Company clarifies the additional $11 million is actually associated with another IPC wheeling contract, the Integrated Transmission Service Agreement ("ITSA"). At the time of direct testimony, the Company did not know the changes to the ITSA and that is what is included in its rebuttal position.

In surrebuttal, the Office did not directly address these contracts but recommends the Commission deny all updates based on events that occurred after the Company's filing date which in this case is June 23, 2009. No other party comments on the Company's proposed increase.

We conclude parties have not had adequate time to review and support or contest the Company's conclusions regarding the IPC ITSA contract. Indeed, the record indicates this is an old and relatively complex contract which the Company knew would need to be renegotiated but failed to specifically identify in its direct case. Introducing this contract in rebuttal provides insufficient time for parties to conduct discovery or evaluate the proposed changes, let alone support or contest the changes. Additionally, there is no supporting evidence regarding the details of the new contract. For these reasons, we do not accept this rebuttal adjustment by the Company.

u. Coal Costs

In its direct testimony, the Division testifies the Company makes assumptions about general inflation, escalation of wages and benefits, the cost of commodities such as diesel fuel, natural gas and other petroleum products in order to develop coal costs in the test period. The Division testifies the Company has used inconsistent assumptions for general inflation and out-of-date commodity costs. The Division argues the Company has not provided spreadsheets in electronic form so it is unable to provide its recommended coal costs and may update its recommendation in rebuttal. In supplemental direct testimony, the Division recommends use of the updated coal costs and proposes an adjustment to reduce the forecast of total Company net power cost by $2.6 million.

In rebuttal, the Company does not oppose the Division's adjustment on "...two conditions. First, if the Commission adopts the Division's proposed update to coal costs, then the updates proposed in [the Company's] rebuttal testimony should also be adopted to ensure that changes are symmetric. Second, the Commission should allow updates to coal costs in future proceedings as long as it is based on data available as of the time intervening parties filed their direct testimonies."

We accept the Division's adjustment to coal costs as a reasonable effort to ensure the best available information is used in this proceeding. The Division identified this issue in its direct testimony and it appears it would have had an adjustment to propose if the Company had supplied the necessary electronic spreadsheets more timely. Data responses should be provided to intervenors in electronic format to enable review of calculations and facilitate efficiency. This decision reduces the Company's forecast of Utah test period revenue requirement by $1.090 million and is reflected in Table 1.

4. Labor Costs

The Company's forecast of total labor-related costs for the test period, the 12 months ending June 2010, is based on the actual labor-related costs for the 12 months ending December 2008, termed "the base year." Labor-related costs for the base year were $694.3 million. Of the labor-related costs, $202.2 million, or 29.1 percent, were classified as capitalized and non-utility costs, and $492.1 million, or 70.9 percent, were classified as utility expenses.

In rebuttal, the Company's forecast of total labor-related costs in the test period is $720.7 million, representing an increase of $26.4 million, or 3.8 percent, over the base year. The total labor-related costs for the test period are separated into categories based on the percentages which were incurred in the base year, i.e., 29.1 percent are classified as capitalized and non-utility costs and 70.9 percent are classified as utility expenses. Thus, the labor-related costs in the test period consist of $209.9 million which are classified as capitalized and non-utility costs and $510.8 million which are classified as utility expenses. This represents an increase in labor costs for the test period of \$7.7 million for capitalized and non-utility costs and \$18.7 million for utility expenses, relative to the base year.

During deliberation, Commission staff identified an error in the Company's filing in the "June 2010 Proforma Labor" Table calculation whereby the amounts for Group Code 13, Labor Group "PCCC Non-Exempt" were incorrectly copied from the "December 2008 Annualized Labor Reordered into 12 Months Ending June 2008 " Table. On January 25, 2010, the Commission informed the Company of the identification of this error and requested the Company to confirm in writing whether this observation is correct and if so, whether Commission staff has appropriately calculated the Company's surrebuttal position if the correction is made. On January 27, 2010, the Company verifies this mistake and concurred with the associated correction except for a slight increase in payroll tax, which the Company indicates is immaterial. We find it appropriate to make this correction as it was clearly an unintentional mistake and its correction does have a material affect on change in test period labor expense in this case.

The correction of this error revises the Company's rebuttal position as follows. The Company's forecast of total labor-related costs in the test period is \$725.5 million, representing an increase of \$31.1 million, or 4.5 percent, over the base year. The total labor-related costs for the test period are capitalized and expensed based on the percentages which were incurred in the base year, i.e., 29.1 percent are classified as capitalized and non-utility costs and 70.9 percent are classified as utility expenses. Thus the labor-related costs in the test period consist of \$211.3 million which are classified as capitalized and non-utility costs and \$514.2 million which are classified as utility expenses. This represents an increase in labor costs for the test period of $9.1 million for capitalized and non-utility costs and $22.1 million for utility expenses, relative to the base year. The correction of this error increases the Company's total forecasted labor-related expenses costs by $3.4 million. This decision increases the Company's forecast of Utah test period revenue requirement by $1.381 million and is reflected in Table 1.

The total of labor expenses for the test period is spread to the FERC accounts, and categories within these accounts, based on the relative amounts of actual labor expenses reported in these accounts and categories for the base year ending December 2008. The labor expenses are subsequently apportioned from the Company to its jurisdictions based on the test period interjurisdictional allocation factors associated with the categories within the FERC accounts. Overall, Utah is apportioned 42.8 percent of the Company's labor expenses. Consequently, for the test period, the Company is seeking recovery from the Utah jurisdiction of $210 million in utility labor expenses.

The Division, the Office, and UAE take issue with several aspects of the Company's forecast

a. Pension Administration

In direct testimony the Company proposes a pension administration expense of $0.9 million which is a $0.5 million increase (160 percent) over the base year amount of $0.3 million.

In direct testimony, the Division proposes an adjustment to pension administration expenses. The Division states the Company stated that the 2010 budget used to derive the 2010 pro forma costs for pension administration assumed there would be a greater need for actuarial work due to various union negotiations. The Division maintains that the

Company negotiated retirement changes with two unions in 2008 and the other three union's retirement benefits will be negotiated in 2009 therefore the Company's budgeted increase for additional actuarial work due to various union negotiations will not be realized. The Division proposes an approximately 6 percent increase in pension administration costs over the 2008 level. The Division's proposed adjustment reduces the Company's forecasted revenue requirement by $0.4 million on a total Company basis and $0.2 million on a Utah jurisdictional basis.

In rebuttal testimony the Company reduces the level of expenses included in the test period related to the administrative costs of its pension plan from $0.9 million to $0.7 million due to reduced actuarial work. The Company's revised pension administration cost reflects an annualized level of expenses based on costs incurred from January to September 2009. The Company states that 2008 expenses for pension administration were much less than both the prior three years and the period of January through September 2009. This adjustment results in a reduced revenue requirement amount of $0.1 million on a total Company basis and $0.06 million on a Utah jurisdictional basis.

In addition the Company maintains the Division's adjustment would leave only approximately $0.4 million in the test period for pension administration, a value which is significantly less than any of the three years previous to 2008 and less than the 2009 costs through September. The Company asserts its adjustment to annualize the 2009 actual expenses will result in a more reasonable projection of ongoing pension administration.

In surrebuttal the Division first corrects an error in its escalation rate calculation and then rejects the Company's rebuttal position arguing the Company has offered no additional evidence that its costs for pension administration are going to increase significantly over those in the base year. The Division asserts the Company contention that pension administration expense will increase due to collective bargaining negotiations requiring additional actuarial work is no longer valid. The Division again testifies union agreements were negotiated in 2008 and 2009 and there is no reason to expect significant increases in pension administration costs in 2010. The Division maintains that absent other compelling factors, escalating base period costs with inflation should be acceptable. The Division points out the Company's forecast pension administration expense is 20 percent higher than the average of the previous 4 years. The Division's adjustment results in a reduction of forecasted revenue requirement of $0.4 million on a total Company basis and $0.2 million on a Utah jurisdictional basis. The Division suggests an alterative method to determine this adjustment would be to use the average of previous years pension expenses.

As pointed out by the parties, the Company's pension administration costs have varied dramatically since 2005 as follows: calendar year 2005 - $0.5 million; calendar year 2006 - $0.5 million; calendar year 2007 - $0.9 million; calendar year 2008 - $0.3 million; and January through September, 2009 - $0.5 million. We observe the Company's recommended annualized test year cost of $0.7 million is a 102 percent increase over the 2008 base year. While the Company explains how it calculates its test year costs it only indicates its test year forecast is more "reasonable" than the Division's escalation of base year costs. The Company neither provides any basis for such reasoning as to why test year pension costs will be substantially greater than those incurred in the base year nor why 2009 annualized pension costs will be more reflective of what is anticipated during the test year. Based upon the variability of these costs, lack of Company reasoning, and the Division's testimony that union agreements were negotiated in 2008 and 2009, we accept the Division's adjustment on pension administration costs. In future cases, however, we request testimony and analysis on whether or not pension administration costs should reasonably be averaged over a period of several years. This decision reduces the Company's forecast of Utah test period revenue requirement by $0.156 million and is reflected in Table 1.

b. Pension Expenses

In direct testimony the Company proposes a pension expense of $33.9 million which is an increase of $0.9 million over the base year pension expense.

The Office supports an adjustment to replace the projected test year pension expenses included in the Company's filing with the most recent 2009 amount provided by the Company's actuary. The actuarial forecast is both considerably lower than the projected amounts for 2009 incorporated by the Company in its filing and lower than the base year amounts. The Office asserts pension expenses have been declining for several years due to significant changes in the Company's pension plan and that the Company has not supported its projected increase in the filing. The Office references the Company's pension costs for the year ending December 31, 2007, and December 31, 2008, were $49.1 million and $34.1 million, respectively on a gross basis, representing a decline of $15 million. The Company's updated projected 2009 pension costs, based upon the more recent actuarial reports are $30.5 million which is approximately $2.7 million less than the 2008 cost level. The Office maintains it is not reasonable to assume there will be a significant increase going into 2010. This adjustment reduces the Company's forecasted revenue requirement by $3.1 million on a total Company basis and $1.3 million on a Utah jurisdictional basis.

The Company disagrees with the Office's adjustment and argues the Office's adjustment, which is based upon 2009 actuarial information prepared in October 2009, results in a selective use of the Company's actuary's most recent projection of pension expenses. Further, the Company points out inconsistencies in the Office's position as, on one hand, the Office finds the 2009 actuarial information useful for purposes of proposing an adjustment based upon pension expenses forecast for 2009, yet on the other hand the Office refuses to accept the same report for purposes of the forecast for pension expenses projected for 2010.

As reflected in substituted RMP Cross Exhibit 9, the Company's pension consultant Hewitt and Associates ("Hewitt") projects pension expenses for 2010 to be $21.8 million more than the pension expenses requested in the test year for 2010. The Company argues Hewitt indicates that pension costs are increasing due to a change in the discount rate and the continued effect of recent stock market performance on the plan investments. At hearing the Company testifies its pension is currently 81 percent funded. The Company concludes that because the overall pension and post-retirement expenses reflected in the revenue requirement are less than the most current actuarial projection of these expenses, there is no basis for the reduction in the Company's ability to fully recover these proposed expenses. The Company recommends that since updating the pension expense calculation using the most recent actuarial information from Hewitt would result in a slightly higher expense than the amount originally filed, the Company proposes to leave the pension expense as filed.

In response to rebuttal testimony, the Office argues the Company has significantly reduced the discount rate used in its calculations, from 6.90 percent to 5.75 percent, for the purposes of projecting the 2010 pension costs. In addition, the Company has assumed an actual return on plan assets for 2009 of 14 percent. The Office points out the actuarial projects in the Company's filing assumed a long term rate of return on plan assets of 7.75 percent for 2009 and an actual return on plan assets for 2009 of 14 percent, but according to a response to a data request the return on pension plan assets for year-to-date through October 31, 2009 was 16.7 percent with two months remaining in 2009. In summary, the Office indicates the actual earnings for year-to-date through October 31, 2009, have exceeded the assumptions used in the updated projects used by the Company in rebuttal testimony.

In light of the current unpredictable nature of the economy in general, fluctuating stock market performance, and the funding status of the Company's pension plan we are not persuaded by the Office's arguments regarding using an updated forecast of discount rates and rates of return on plan assets. We accept the Company's proposed pension costs.

c. Other Post Retirement Benefits

In direct testimony the Company proposes a post retirement benefits - FAS 106 expense of $17.7 million which is a decrease of $3.9 million from the test year pension expense.

Similar to pension plan costs addressed above, the Office recommends an adjustment to replace the post retirement benefits expense included in the Company's filing with the most recent 2009 amount provided by the Company's actuary, Hewitt. This adjustment reduces the Company's forecasted revenue requirement by $0.9 million on a total Company basis and $0.4 million on a Utah jurisdictional basis. The Office asserts the costs associated with post-retirement benefits other than pensions have been declining in recent years. The Office references the Company's other post-retirement benefits expenses for the year ending December 31, 2007, and December 31, 2008, were $26.7 million and $22.2 million, respectively on a gross basis, representing a decline of $4.5 million. The Company's updated projected 2009 pension costs, based upon the more recent actuarial reports are $16.8 million which is approximately $0.6 million less than the amount incorporated in the filing and $5.4 million less than the amount incurred during 2008. In rebuttal the Office continues to assert post retirement benefit expenses have been declining for several years and that the Company has not supported its projected increase in the filing.

The Company disagrees with the Office's adjustment and argues post-retirement benefit expenses should be allowed at the proposed level. The Company maintains the Office has suggested an adjustment to the post retirement benefits costs in order to account for changes it believes have occurred in the market and argues the Office's adjustment, which is based upon 2009 actuarial information, results in a selective use of the Company's actuary's most recent projection of post retirement benefit expenses prepared in October 2009. Further the Company suggests the Office finds the 2009 actuarial useful for purposes of proposing an adjustment based upon pension expenses forecast for 2009, however, the Office refuses to accept the same report for purposes of the forecast for post-retirement benefit expenses projected for 2010 since the information was not historical, ignoring the fact that this case is based upon a forecast test period. The Company concludes that because the overall pension and post-retirement expenses reflected in the revenue requirement are less than the most current actuarial projection of these expenses, there is no basis for the reduction in the Company's ability to fully recover these proposed expenses.

In response to rebuttal testimony, the Office argues the Company has significantly reduced the discount rate, from 6.90 percent to 5.75 percent, for the purposes of projecting the 2010 post retirement benefit costs. In addition, the Company has assumed an actual return on plan assets for 2009 of 14 percent; the discount rate will not be selected by the Company until December 31, 2009; and the actuarial projects in the Company's filing assumed a long term rate of return on plan assets of 7.75 percent for 2009. The Office indicates the actual earning for year-to-date through October 31, 2009, have exceeded the assumptions used in the updated projections used by the Company in rebuttal testimony.

At hearing the Company indicated that as advised by Hewitt, using the November 30, 2009, data, specifically the discount rate and an assumed rate of return of 20 percent, would produce an increase in the 2010 expense as filed. Therefore, the Company would support maintaining the post retirement benefit expense represented in the initial filing.

In light of the current unpredictable economy and fluctuating stock market performance we are not persuaded by the Office's arguments regarding forecasting discount rates and rates of return on plan assets. We accept the Company's proposed other post-retirement benefit costs.

d. Remove Chehalis Due Diligence Bonuses

In direct testimony the Company proposes a bonus expense amount of $1.6 million which is an increase of $0.1 million over the base year bonus expense. This amount is above and beyond that included in the case for the Company's annual incentive plan. In rebuttal, the Company decreases its proposed bonus expense amount to $1.6 million to reflect accepted adjustments. This revised estimate reflects an increase of $0.1 million over the base year bonus expense on a Utah jurisdictional bases.

The Office proposes reducing the Company's forecasted test year expenses by $0.2 million on a total Company basis and $0.08 on a Utah jurisdiction basis to remove the Chehalis Due Diligence Bonuses ("Chehalis Bonuses") that were paid by the Company during the base year, otherwise referred to as "out of period" expenses. The Office maintains the Chehalis bonuses were specific to the Chehalis acquisition and will not be repeated in the test year. The Office indicates that Account 500400 - bonuses for the test year is in addition to the $32.5 million included for the annual incentive payments. After the recommended adjustment, adjusted test year expenses would still include substantial amounts for bonuses and incentive payments.

The Company disagrees with this adjustment. The Company concurs that the Office is correct that the Chehalis-specific bonus payment will not be incurred during the test period, however, the Company will continue to incur similar bonus type payments on a routine basis throughout the test year. These bonuses contained in Account 500400 are intended to reward and motivate employees to perform at a high level. The Company maintains the very nature of the account suggests that individual awards will be one-time events, but the overall level of expense for this account included in the test period can reasonably be expected to occur again during the test period and into the future.

Small one-time bonuses are an effective way to reward employees for a job well done for a specific project and it is important for the Company to be able to exercise discretion to recognize employees in this way. The efforts the Company undertook to procure the Chehalis Generating station were indeed worthy of this type of recognition. With the Company's construction program and operations and maintenance goals it is reasonable to assume that employee recognition may be warranted for other similar achievements resulting in positive outcomes for the Company and its ratepayers. We agree with the Company's position on this issue and decline to accept the Office's adjustment.

e. Supplemental Executive Retirement Program

In direct testimony the Company proposes a supplemental executive retirement plan ("SERP") expense amount of $2.4 million which is an decrease of $1.0 million from the test year SERP expense.

Both the Division and the Office recommend removing costs associated with the Supplemental Executive Retirement Plan ("SERP" or "Plan") from rates. This adjustment would result in a reduction of revenue requirement by $2.4 million on a total Company basis and $0.7 million for the Utah jurisdiction.

The Division explains that SERP's are provided for highly compensated individuals because benefits under general retirement plans are subject to limitations by the Internal Revenue Code. In 2008 the Company President was the only active executive that participated in the SERP, and the SERP is currently closed to any new participants. Other retirees, beneficiaries, and others with deferred benefits are benefitting from the Plan based upon past employment. The Division argues executive benefit costs should be shared such that executive benefits included in the Company's regular pension and 401(k) plans should be included in rates, while the cost of the additional executive benefits paid to the Company

President and included the SERP should be excluded from rates and paid for by shareholders. The Division states that officers of a corporation should be loyal to the corporation and are motivated by the interest of the company and its shareholders first. The award of the SERP each year is tied directly to the Company meeting certain performance goals and the interests of the shareholders and ratepayers are not always aligned.

The Office maintains ratepayers should not be required to indefinitely fund the SERP costs associated with past employees participating in the plan and the one active employee currently in the plan indefinitely into the future regardless of the circumstances. While acknowledging that the Commission, in Docket 99-035-10,[10] indicated the SERP plan was an essential part in recruiting qualified executives, the Office believes circumstances have changed since the order in the case was issued on May 24, 2000. Not only has the Plan been closed to new participants for several years, but only one current executive at the Company participates in the SERP. The Office maintains the question at hand is whether Utah ratepayers should in perpetuity pay the plan's cost when no evidence demonstrates that SERP provides a present or future ratepayer advantage. In addition, the Company's Utah customers can ill afford to provide these benefits, particularly when they are receiving no service for the vast majority of the costs.

The Company disagrees with the Division and the Office's recommendation. The Company argues SERP expenses are not extra, unnecessary or excessive benefits. The expenses sought are related to one active participant and past participants who, during their employment, delivered value to the then current customers while also shaping the Company to benefit future

[10] Docket No. 99-035-10, "In the Matter of Application of PacifiCorp for Approval of its Proposed Electric Rate Schedules and Electric Service Regulations."

(current) customers. The Company argues the SERP expense is a form of retirement/pension similar to the frozen benefit expense of the non-union employee population who shifted on June 1, 2007, to a cash balance. The Company points out that the Utah Commission has historically taken the position that the SERP benefit is a benefit offering that is competitive with the market and the Commission has, in turn, approved the expenses in prior rate cases.

Since our May 24, 2000, Order in Docket No. 99-035-10 in which we indicated the SERP was an essential part in recruiting qualified executives, circumstances have changed and the Company has reacted by closing SERP to new participants. Neither closing the plan to new participants, the current economy, nor hindsight assessments of the plan negates the Company's responsibility to continue funding the Plan for past and current employees. Nor does it change the cost associated with the SERP from being a legitimate expense incurred by the Company and uncontested by parties in other recent rate cases to one which is now unreasonable. We agree with Company's position and decline to accept the Division's and Office's adjustment. We accept the Company's proposed expense level.

f. Remove Supplemental Executive Retirement Plan and Bonuses from MEHC Management Fee

In direct testimony the Company includes expenses associated with MidAmerican Energy Holding Company ("MEHC") SERP ($0.4 million), MEHC bonuses ($1.8 million), and MidAmerican Energy Company ("MEC") bonuses ($0.1 million) in its test period forecast of the MEHC Management Fee charged to the Company.

The Office proposes an adjustment to exclude costs associated with MEHC SERP, MEHC bonuses, and MEC bonuses included in the MEHC management fee from costs that are passed on to ratepayers. This adjustment reduces the test period forecast of MEHC management charges by $2.4 million on a total Company basis and $1.0 million on a Utah jurisdictional basis. The Office's recommendation to remove MEHC SERP is consistent with its recommendation above.

Regarding MEHC bonuses the Office maintains the Company did not provide the targets under the MEHC bonus plan, only copies of PacifiCorp's annual incentive plans and a partially redacted copy of the MEHC 2009 goals which only provided goals applicable to the Company. The Office provides a confidential summary of the 2009 MEHC goals. In addition, the Company did not provide, in responses to data requests, the MEC goals which drive the MEC bonus amounts. The Office therefore recommends these amounts be removed from costs passed on to customers.

The Company disagrees with the Office's recommended adjustment to MEHC management fees as it believes they are reasonable, above-the-line costs. The Company maintains it has benefitted, and will continue to benefit, from having MEHC as its holding company and then lists several benefits including MEHC cost cutting strategies which have saved ratepayers million of dollars, MEHC's safety policies which have made a positive difference in the Company's safety record, corporate functions performed by MEHC on behalf of the Company, and the fact that because the Company is now privately held there are no shareholders' services costs which must be paid. The Company contends it has demonstrated that as a result of MEHC's philosophy of running a streamlined company, millions of dollars have been saved to the benefit of both the Company and the Company's ratepayers.

In addition, the Company testified the March 2006 results of operations filed with the Commission indicates a total Company administration and general ("A&G") expense of greater than $240 million. As part of the MEHC transaction, MEHC agreed to a stretch pool of $222.8 million adjusted for inflation as a merger commitment for A&G costs with several states. In this case, the Company has delivered A&G of less than $180 million, which is more than $40 million below the target set at the time of the transaction.

In response to questions from the Office pertaining to whether a one-time special achievement bonus of $8.5 million awarded to Mr. Sokol in 2008 for having relinquished his CEO position and remaining as chairman was charged to PacifiCorp and whether the Company had knowledge of a $5.0 million dollar bonus paid to Mr. Abel, the Company responded it did not know or had no knowledge, respectively. The Company also testified it did not ask, nor was it told, if there was any special one-time charges in this MEHC bonus amount allocated to PacifiCorp.

Regarding MEHC SERP costs, the Company also believes they are reasonable because they are an essential part of executive compensation in retaining the types of highly qualified executives that make decisions with positive impacts on ratepayers. As with the previous adjustment, the Company references the Commission's decision on SERP in Docket No. 99-035-10 in which the Commission determined SERP was an essential part for recruiting qualified executives. With the exception of the one active participant, the remaining expense should be viewed no differently than pension expense, as it is a commitment by the Company to the employee for their service, while also maintaining the competitive position.

In surrebuttal, the Office argues that the Company, with the exception of SERP charges, does not address the specific management charges that it recommended for removal. Further, the Company did not provide targets under either the MEHC or MEC incentive plans for the base year. The Office maintains any improvements which may have occurred since the acquisition of the Company as compared with prior ownership would not justify the inclusion of MEHC bonuses, MEC bonuses, and MEHC SERP costs in rates. These management fees charged by MEHC should still be scrutinized to ensure that the costs ultimately allocated to the Company and charged to its customers are reasonable and appropriate. The Office maintains that SERP is clearly not "an essential part of executive compensation in recruiting and retaining qualified executives" as it may have been at the time of Docket No. 99-035-10.

Consistent with our decision above, we decline to accept the Office's adjustment regarding MEHC SERP expenses. Regarding other components of the MEHC management fee in dispute, namely MEHC and MEC bonuses, the Company provides persuasive testimony of the benefits of MEHC Management to PacifiCorp up until now, including decreases in A&G expenses, decreases in some labor expenses through time, and improvement in the Company's safety record. In this case, we find the MEHC and MEC bonus a reasonable component of the MEHC management fee. We do want to ensure, however, that in future cases the Company is consistently reviewing data upon which the Company's revenue requirement is forecast. With respect to MEC and MEHC bonuses we direct the Company, if requested by any party in applicable future proceedings subject to confidentiality provisions, to provide a detailed summary of the components of the test year bonus amount, whether any of the components of the test year reflect one-time bonuses, and the associated information pertaining to performance goals upon which the bonuses are based, and data representing successful completion of these goals.

5. Other Expense Adjustments

a. Uncollectible Accounts Expense

In direct testimony, the Company forecasts Utah's uncollectible accounts expense, or bad debt expense, by escalating the actual amount in the base year to the test year. The ratio of these uncollectible expenses to general business revenues is termed the uncollectible rate. In the Company's direct testimony, the uncollectible rate in the test year for Utah is 0.4 percent.

Since the uncollectible rate was 0.216 percent, 0.213 percent and 0.312 percent, in 2006, 2007, and 2008, respectively, the Division views the uncollectible rate and associated expense for the base year as abnormally high. Escalating the base year amount does not adequately account for the unforeseen events that have taken place in the economy during 2008 and through September 2009. The Division proposes applying a three-year average of uncollectible rates, or 0.247 percent, to the test year forecast of general business revenues to produce a test year forecast of uncollectible expense.

In rebuttal testimony the Company proposes applying the uncollectible rate resulting from its June 2010 budget, (the "target" rate) or 0.27 percent, to its test year forecast of general business revenues to produce a test year forecast of uncollectible expense. According to the Company, since 2006 and 2007 were years in which the economy was relatively healthy, a three-year average fails to account for the steep downturn in recent economic conditions. Also, the uncollectible rate for January through September 2009 is 0.346 percent, greater than the rate for 2008, thus indicating no sign of an economic recovery. The Company asserts it is unreasonable to assume the economy will recover by June 2010 to the levels experienced in 2006 and 2007. Since the Company's test year target rate is less than the rate for 2008 or through September 2009, it should be judged reasonable and justified. If the Division's averaging proposal is accepted, the Company requests it be applied consistently in future proceedings, not just when it results in a lower rate increase.

In surrebuttal testimony the Division expresses its concern the target uncollectible rate used in the Company's budget, a result of management discretion, is not subject to audit. The Division states the use of a three-year average to construct the test year uncollectible rate is a reasonable way to normalize and forecast an expense which fluctuates significantly from year to year.

In direct testimony the Office makes no adjustment to uncollectible expense. In rebuttal testimony the Office agrees with the Division's conclusion the uncollectible expense in the Company's direct testimony is too high and the Office supports the Division's use of a three-year average uncollectible rate. In surrebuttal testimony the Office supports the Company's use of the target uncollectible rate.

When historical test years are used for ratemaking, typically an average over time of uncollectible expenses is used to normalize this expense. With the move to future test years, this expense has been forecasted by escalating an historical (base year) expense amount. However, by the end of this case, parties propose to forecast this expense by applying different uncollectible rates to the test year forecast of general business revenues. This use of an uncollectible rate represents a different approach to determining this expense. In addition, at issue is whether this rate is based on an historical average or a management forecast.

All parties recognize the expense in the base period is abnormal. 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. We are not persuaded the use of an uncollectible rate, and its reliance on test period revenues, is more appropriate than escalating a normalized base period expense, an approach independent of revenues. To determine a general policy, additional evidence comparing these two approaches is necessary. This decision reduces the Company's forecast of Utah test period revenue requirement by $1.617 million and is reflected in Table 1.

b. Injuries and Damages

In the Company's last rate case, Docket No. 07-035-93, the Commission ordered the Company to use an average of historical expenses to forecast a normal level of injuries and damages expense. Absent testimony on the specific length of time over which an average should be constructed, the Commission accepted the three-year average recommended by the Office, while stating a five-year average would be acceptable for this type of account. The Commission also ordered this expense be stated on a cash rather than accrual basis.

Consistent with the order in Docket No. 07-053-93, in this case the Company uses a three-year average ending with the base year to normalize this expense. The Company believes three years is an appropriate time frame to smooth variations from one year to the next, and believes the period over which an historical average is constructed should end in the same year as the base year used to construct the future test period, consistent with other averages.

Due to the wide variations experienced by the net cash amount for injuries and damages since 2004, the Division now recommends using an average over five year ending July 2009, the most recent month for which information is available. The Division's proposed adjustment reduces the Company's test year forecast revenue requirement by $0.2 million on a total Company basis and $0.1 million on a Utah jurisdictional basis.

The Company points out if the Division's five-year average was constructed over the period ending December 2008, the base year, rather than July 2009, then this expense would be higher than the Company's currently proposed amount for this adjustment by $0.5 million, of which about $0.2 million would be allocated to Utah. The Company recommends if a 5-year average is adopted, the period should still end with the base period.

Given the Company's method is consistent with our order in Docket No. 07-035-93, we decline to adopt the Division's adjustment.

c. Remove Settlement Fees

In the Company's direct testimony, Account 925 - Injuries and Damages includes $0.5 million in the base year for restitution associated with an avian matter and Account 506 - Miscellaneous Steam Plant Expenses includes $1.2 million in the base year for the settlement resolving litigation associated with leaking ponds at the Colstrip Power Plant.

The Office maintains ratepayers should not bear the cost of the Colstrip settlement. In addition, the Office argues the Company did not provide support for its position regarding the amounts and types of settlement fees it has incurred over the past three years. This adjustment reduces the Company's forecast of revenue requirement by $1.7 million on a total Company basis and $0.7 million on a Utah jurisdictional basis.

The Company maintains a certain level of legal risk is inherent in the nature of the electric utility industry and that settlement and legal expenses are unavoidable and necessary. In rebuttal testimony the Company states in the past three historical calendar years, the Company has averaged approximately $2.2 million in these types of settlement fees. The settlement fees proposed for removal by the Office are well within the normal range that the Company regularly incurs. In preparation of a data request, however, the Company identified some settlement fees included in the calculation of the $2.2 million average that should not have been and felt it appropriate to revise its position regarding the fees for the Colstrip and Avian settlements. Therefore the Company removes expenses associated with the avian matter and proposes inclusion of the Colstrip settlement amortized over a period of three years. The Company's updated position reduces its forecast test period revenue requirement by $1.3 million on a total Company basis and $0.5 million on a Utah jurisdictional basis.

At hearing the Office questions the Company regarding insurance proceeds related to the Colstrip Settlement. When asked by the Office if it was true that an insurance claim had been made which is outstanding and reduces the Colstrip Settlement by approximately one half, the Company responded that it did not have any details on that. The Office then asked the Company to review pages from a report filed entitled "Background of Settlement of Claims, Duane and Carol Ankney vs. Avista Corporation." Upon review the Company agreed the report indicated PacifiCorp's obligation net of potential insurance would be $0.7 million rather than $1.2 million. The Company later indicated if the Colstrip settlement costs are allowed in this rate case as proposed by the Company, it will take any insurance settlements given to the Company and will give those insurance settlement monies back to the Utah customers.

The Office disagrees with the amortization proposed by the Company in this issue for the following reasons. First, based upon documents available online from other filings from other joint owners of the Colstrip plant, there is a good chance there will be insurance recoveries to recover a portion of that cost; and second, once the Colstrip settlement payments have been removed, the test year still includes approximately $0.8 million worth of settlement-related costs which, in the Office's opinion, is a reasonable level going forward. The Office concludes that as a non-recurring expense incurred before the test period, that is partially insured and for which no supporting information was provided, the entire amount should be removed.

We recognize the Company is subject to litigation from events occurring in the past for which there were no laws or rules in place and we agree that settlement and legal expenses associated with some past events, depending on the circumstance, are legitimate and unavoidable expenses. On the other hand, once a law or rule is passed as a matter of policy, the Company is responsible to ensure compliance with these laws or rules until such time that the laws or rules are changed. To the extent they do not, shareholders bear the risks of non-compliance costs occurring.

We understand the Company's removal of the avian settlement fees and its deferred accounting proposal for the Colstrip Settlement were offered to address the discovery that settlement fees included in the base period are above previous levels. In addition, we agree with the Company that a certain level of legal risk is inherent in the nature of the electric utility industry and that settlement and legal expenses are unavoidable. In fact, the Company's testimony leads us to conclude payment of settlement fees is not an extraordinary event. In addition, since many settlement fees arise from settlements which may, at times take many years to complete, payment of some settlement fees is most likely not an unforseen event.

Our task here is to set a reasonable level of settlement fees to be included in the base period. We do not agree with the Office that the Colstrip Settlement Fee should be removed from base year settlement fees in order to forecast test year expenses. Rather the Company should be provided with a sustainable level of settlement fees which will address these issues as they occur on an on-going basis. Therefore we accept the Company's proposal in part and agree with the Company's rebuttal position in which it reduced its forecast test period revenue requirement by $1.3 million on a total Company basis and $0.5 million on a Utah jurisdictional basis. As the amount of the adjustment reflects the Company's own recommendation to revise its position to correct an error we assume it will provide it a reasonable amount of settlement fees on an on-going basis.

However, we do not accept the Company's amortization proposal, particularly in light of the fact this adjustment was proposed in surrebuttal testimony in order to correct identified errors. The Company neither provides testimony on why amortization is appropriate or necessary in this case nor explains why the Colstrip settlement fee should be treated differently from any other settlement fee. Nor does the Company explain how this particular settlement fee meets general guidelines for allowance of deferred accounting proffered by parties in previous deferred accounting cases presented before the Commission. It was also not clear how the Company would treat insurance refunds associated with the Colstrip settlement.

Because settlement fees as discussed here are not extraordinary events and the Company provided scant testimony on the subject we are persuaded by the Office to reject the Company's proposal to amortize the Colstrip settlement fee over three years.

We are concerned that it is difficult for parties to review and evaluate settlement fees because they are scattered throughout various accounts. We direct the Company in its next general rate case application to provide a summary exhibit detailing actual settlement fees for the past five years and proposed test year settlement fees so a detailed review may occur.

This decision reduces the Company's forecast of Utah test period revenue requirement by $0.541 million and is reflected in Table 1.

d. Airplane Expense

In direct testimony the Company includes $1.0 million of above the line airplane expense on a total Company basis. In rebuttal, the Company removes $0.1 million on a total Company basis and $0.03 million on a Utah allocated basis from FERC accounts 557, 908, and 921 to adjust for costs associated with flights that should have been charged below-the line, that did not provide a benefit to Utah, and were associated with IPP3 lawsuits.

The Division proposes a reduction to the Company's rebuttal test period forecast of corporate airplane expenses by approximately $0.2 million on a total Company basis or approximately $0.05 million on a Utah basis. The Division maintains the Company's description of the disputed trips for which the Division is making an adjustment are not compelling, nor do they provide enough information to determine if the trips had a direct benefit to Utah ratepayers.

The Division references three trips to Boise, Idaho by Company personnel to work with Idaho federal and state legislators which the Company explains are to discuss proposed legislation that would either be deleterious or beneficial to Utah customers. The Company provided no further explanation in the form of copies of agendas, minutes of meetings, or handouts. The Division asserts the Company is reticent to specifically explain and provide specific proof on how and why, and when the trips to other states did and will benefit Utah. The Division also references one overnight round trip to Des Moines, Iowa, for one person (total Company cost of $7,292 with Utah allocated amount of $2,999) with the purposes of meeting with Greg Abel and Siemens to discuss various business issues.

We appreciate the Division's attention to detail on this issue as its inquiry has resulted in the Company reviewing its charges and removing those which are not appropriate. We also trust that the Company will continue to prudently manage its use of the corporate airplane by evaluating both benefits and costs of such airplane use prior to flying and documenting in detail the use of the Company plane. In our review of the Division's remaining disputed trips we observe that many are to visit governors or legislators in other states. Under the assumption that the disputed trips have been properly evaluated for use of the airplane, we find these types of trips appropriate as the Company operates generation and/or transmission facilities in many states throughout the West which could be discussed during any one of these meetings. In addition, these types of trips may be necessary for the Company to formulate strategic policies which will affect the entire Company – not just Utah. With this in mind, we find the difference between the Company's and the Division's position on this issue immaterial and accept the Company's airplane adjustment. This decision reduces the Company's forecast of Utah test period revenue requirement by $0.030 million and is reflected in Table 1.

e. Rent Expense

The Company's direct testimony includes $0.1 million on a total Company basis for One Utah Center Sub-leases #5 and #6. The Company explains the Sub-leases #5 and #6 are for $1 per month rent plus operating expenses and are provided to the Economic Development Corporation of Utah ("EDCU") and the Utah Sports Authority, and the lease expense about $1 per month is included as a challenge grant expense, situs assigned to Utah in FERC Account 930.

The Company believes this is an appropriate cost that benefits Utah customers and the state as a whole. The Company has worked with economic development organizations throughout its service territory in an effort to provide accurate timely information to companies considering expansion or relocation within the Company's service territory; help direct companies to locations where sufficient capacity exists to meet their needs at an acceptable cost; and influence economic development policies that impact overall cost of energy to existing electric customers. Making these contributions to EDCU and other entities by absorbing lease expenses is a key element to partnering with economic development organizations that, in effect, become an industrial customer's first point of contact in the state. The Company concludes by stating that if these expenses are not allowed to be recovered in rates the Company would be forced to cancel or renegotiate these contracts.

The Division recommends that One Utah Center Sub-leases #5 and #6 should be removed from the revenue requirement. The Division asserts the Company made the exact same adjustment for these sub-leases in Docket No. 08-035-38 as the Division is making in this case and points out the Company now argues that the subsidizing of this rent to the two occupants is an appropriate cost that benefits the Company's customers and the state as a whole. The Division states ". . . the Company is explaining an in-kind charitable contribution or subsidizing of free office space to these non-profit organizations. . ." and therefore maintains these costs should not be included in determining the revenue requirement in this case. The Division concludes that if the Company does not want to cancel or renegotiate the contracts it has the option to help these organizations through keeping the contribution/subsidy but accounting for it below the line.

In addition to the Division's testimony that the Company made a similar adjustment for these sub-leases in Docket No. 08-035-38 which the Division is proposing in this case, we also note the Company made a similar adjustment for these sub-leases in Docket No. 07-035-93. We concur with the Company that economic development activities are important to the state. However in this case the Company provided no explanation as to the change in circumstances whereby it now believes recovery of these lease expenses is appropriate whereas this adjustment was accepted by the Company in the previous two rate cases. We therefore accept the Division's rent expense adjustment. This decision reduces the Company's forecast of Utah test period revenue requirement by $0.118 million and is reflected in Table 1.

f. Generation Overhaul

This adjustment was previously decided by the Commission in a prior general rate case, Docket No. 07-035-93. In that docket, the Company forecasted generation overhaul expense by escalating an actual amount from a base year into the test year. Because of the significant annual variations in this expense, the Office recommended normalizing this expense using a four-year average of actual expenses. The Company agreed to use a four-year average, but escalated the actual expense of each of the four historical years to the test year, then calculated an average of the escalated amounts. The Company also included budget information for newer generating plants. The Commission rejected the Company's use of escalated values for the older plants, ordered instead a four-year average of actual values, and accepted the use of budget information for newer plants, resulting in $32.8 million in generation overhaul expenses in a December 2008 test year. The Company then requested the Commission reconsider its decision, but the Commission declined.

In the next general rate case, Docket No. 08-035-38, the Company again used an average of escalated expenses for older plants, believing the Commission's decision in Docket No. 07-035-93 was inappropriate. However, all revenue requirement issues in Docket No. 08-035-38 were subsequently settled by stipulation.

In this case, the Company has again used a four-year average of escalated actual overhaul expenses to normalize the amount in the base year for the older plants. It has also included in the base year a mix of actual and budget information for the newer plants (Currant Creek, Lake Side and Chehalis), and is requesting a total of $35 million in generation overhaul expenses for the base year (this value is then escalated from the base year to the test year in a separate adjustment). Once again the Company maintains escalation is necessary so the expense amounts in the average, adjusted for the time value of money and inflation, properly reflect the expense associated with generation overhauls.

The parties agree on the test year overhaul expenses for the newer plants. For the older plants, however, the Company and the Office still disagree on whether or not to escalate historical expenses prior to averaging.

The Office opposes escalation, asserting no new supporting evidence has been presented by the Company in this case which had not already been considered by the Commission in making its determination to exclude escalation in the prior docket. Therefore, consistent with the decision in Docket No. 07-035-93, the Office uses a four-year average of actual generation overhaul expenses without escalation for the older plants. This, in addition to the agreed upon expenses for the new plants, totals $32.5 million in base year overhaul expenses.

In its direct testimony, the Division used, for the older plants, an average without escalation, consistent with Docket No. 07-035-93. In its surrebuttal testimony, the Division adopted the Company's position. The Division compared averaging escalated values and escalating an averaged value. According to the Division, the Commission could choose to leave the issue open for more discussion, if needed, in future cases without making any broad policy decisions here, but it recommends the adjustment adopted in the 2007 rate case not be made in this case.

As stated above, in Docket No. 07-035-23 the Commission allowed in the test year $32.8 million in generation overhaul expenses. However for that same period (i.e., 2008), the Company actually incurred $23.7 million (exclusive of the Chehalis plant), or $9.1 million less than the amount then allowed recovery. Now, again for 2008, the base period in the current case, the Company proposes $35 million. From this information we observe the Company is requesting more than they have incurred in any of the last four years and approximately 50 percent more than occurred in the most recent year, 2008.

In addition to those reasons enunciated in our prior order in Docket No. 07-035-93, the Company provides no analysis of how their approach when applied to historical data provides reasonable results over time. The evidence provided in this case, and in other recent cases, is not sufficient to support adoption of the Company's method. For these reasons we do not accept the Company's recommendation, rather we uphold our original decision in Docket No. 07-035-23 and therefore accept the Office's adjustment. This decision reduces the Company's forecast of Utah test period revenue requirement by $1.478 million and is reflected in Table 1.

g. Reverse Distribution O&M Normalization Adjustment

In direct testimony the Company includes an adjustment of $3.5 million situs assigned to Utah to normalize Utah distribution corrective and preventative maintenance expense for the year ending December 31, 2008. For the months of September through December 2008 the Company temporarily decreased spending for the Utah Distribution corrective and preventative maintenance to keep Utah costs in line with the amount included in the forecast test period approved in Docket No. 07-035-93. The Company explains that in 2009 it returned to normal activity levels and argues this adjustment is needed to reflect Utah distribution expense at a sustainable and normal annual level.

The Office contends that the Company failed to provide factual evidence in support of its proposed $3.5 million adjustment to increase Utah distribution preventative and corrective maintenance expense. The Office also references Utah Department of Business

Regulation v. Public Service Commission, which recognizes that in adjusting rates there must be "substantial evidence concerning every significant element in the rate making components (expense or investment) which is claimed by the applicant as the basis to justify a rate adjustment." The Office maintains that in making its adjustment, the Company merely compared budgeted to actual costs in a subset of accounts. The Company did not identify what specific maintenance items were foregone, did not identify specific costs that otherwise would have been incurred, and was unable to provide any written documentation provided to employees giving direction or instructions pertaining to the purported reduction in Utah distribution corrective and preventative maintenance expenditures. The Office asserts the Company apparently took no steps to document or track for future identification, the specific cost reductions and modifications in procedures it contends it undertook, thereby making it impossible to verify the necessity or justification for the proposed $3.5 million adjustment to preventative and corrective maintenance expense for the test period.

The Office argues merely comparing budgeted amounts in certain sub-accounts to actual amounts recorded in those accounts does not support the adjustment. The Office contends the Company's comparison of historic external contractor costs is misleading in that it includes not only external contractor costs specific to the Utah corrective and preventative maintenance expenses, but incorporates all Utah situs contract labor costs, the majority of which were capital costs and not expenses. In summary, while the Office agrees a reasonable level of distribution corrective and preventative maintenance is necessary to maintain reliable service, this does not excuse the Company from providing substantial evidence in support of its proposed adjustments.

The Company argues the level of distribution maintenance must be re-set to properly maintain the distribution system. The Company explains that during September through December 2008 it reduced some inspection cycles from every month to every other month, reduced pole tests and treatment work, as well as reducing other Utah substation and equipment maintenance expenditures. The Company further explains contract labor provides services for both distribution capital investment projects, as well as preventive and corrective maintenance. When the Company reduced preventive and corrective maintenance work from September through December 2008, contract labor was reduced, and internal labor was deployed to capital investments in transmission and distribution projects.

The Company maintains attachments to RMP-RR Cross Exhibit 8 document reductions to contractor services for the period of September through December 2008 by over $1 million. The same attachment further documents reduced expenditures throughout the various Utah operational regions for the same months at substations and operating units. The Company concludes substantial evidence was presented in support of re-setting the Utah preventive and corrective maintenance expenditures level. The $3.5 million additional revenue is reasonable and supported by the testimony and exhibits. The Company argues the Office's reluctance to accept this evidence is an insufficient reason to reject these reasonable and necessary maintenance costs.

We recognize the effect deferred distribution maintenance can have on system reliability and have supported the Company's request for maintenance spending in the past. While we were disappointed the Company chose to decrease maintenance spending in 2008, we realize in the setting of just and reasonable rates in this case it is important to ensure that the revenue requirement reflects a reasonable level of expenses for distribution maintenance activities in the test year.

Our evaluation of this issue, which is primarily based on RMP-RR Cross Exhibit 8, Attachment OCS 24.8a, can be summarized as follows. In 2007, the Company spent a grand total of $51.8 million on Contractor Services Expenditures comprised of $13.4 million of expense charges and $38.4 million of capital charges. In 2008, the Company spent a grand total of $52.6 million on Contractor Services Expenditures comprised of $10.6 million of expense charges and $42.0 million of capital charges. In 2007, through August the Company spent $8.4 million on expense contractor services and $25 million on capital contractor services. By the end of the same period in 2008, the Company spent $8.4 million in expense contractor services and $30.7 million on capital contractor services. During the fourth quarter of 2007 the Company spent $5.1 million on expense contractor services and $13.4 million on capital contractor services. By the end of the same period in 2008, the Company spent $2.2 million in expense contractor services and $11.3 million on capital contractor services. Therefore, in both 2007 and 2008 the Company spent the same amount on expense contractor services through August yet during the fourth quarter 2008 the Company spent approximately $2.9 million less on expense contractor services than in 2007.

We recognize that the costs in Attachment OCS 24.8a only represent Contractor Service Expenditures and Utah preventive and corrective maintenance is a subset of these expenditures. Given the information presented above and the Company's explanation that when it reduced preventive and corrective maintenance work from September through December 2008, contract labor was reduced and internal labor was deployed to capital investments in transmission and distribution projects, we find the Company's argument reasonable and accept the Company's adjustment.

6. Rate Base Adjustments

a. Removal of Hydro Facilities

In its test year, the Company includes the costs of two hydro facilities: St. Anthony located on the Henry Fork of the Snake River near Rexburg, Idaho, and Cline Falls located on the Deschutes River near Redmond, Oregon. Arguing Utah customers receive no benefit from these facilities because they have been discontinued or abandoned, are not currently operating, and provide no electrical service, the Division removed the costs for these facilities. These hydro facilities are currently being used only for the purposes of providing irrigation water: St. Anthony to the Egin Irrigation Canal and Cline Falls to the Central Oregon Irrigation District. This adjustment reduces the Company's forecast Utah revenue requirement by $0.1 million.

According to UIEC, regardless of whether the projects were initially considered prudent investments, these facilities are no longer used and useful in rendering utility service to the Utah ratepayers. If at some future date they are put back into use to render utility service to Utah ratepayers, then at that time, their associated prudent costs would be recoverable. However, at this time, as a matter of law, their costs can no longer be imposed on Utah ratepayers.

According to the Company, the costs of these two facilities should be recovered as is true of the non-functioning Powerdale plant. These plants have provided power in the past, and customers have benefitted from the plants. Any remaining costs associated with the plants should be borne by the customers, since they were the recipient of the benefits. If the Division's adjustment is accepted, the remaining book value should be written off and included in this case.

Regarding these two facilities, there is little evidence regarding the economics associated with the Company's decision not to operate these facilities. The application of the used and usefulness standard does not occur in a vacuum and by itself this standard is not sufficient to determine whether or not cost recovery is warranted. Information on surrounding circumstances such as permit requirements, contractual conditions, and specific operational problems are also necessary. Due to the lack of this evidence we do not accept the Division's adjustment.

b. Coal Inventory Adjustment

In direct testimony the Company includes $160.4 million in rate base to account for fuel stock. The Division proposes reducing the Company's fuel stock by a confidential amount to address what it believes are excessive coal inventories. This adjustment reduces the Company's forecasted revenue requirement by $2.7 million on a Utah jurisdictional basis.

The Division states that during 2008, the base period in this rate case, the Company began to increase significantly the coal inventory levels at the Utah coal plants, in particular, at the Hunter plant. The increases occurred as a result of the Electric Lake Settlement and the West Ridge Agreement and the Division asserts there does not appear to be any plans to bring the inventory levels back to more normal levels.

The Division maintains inventory levels at these plants far exceed both past historic inventory levels and agreements with state commissions as to target inventory levels and inventory levels for other utilities. The Division asserts an interjurisdictional task force addressing coal inventories retained an outside consulting firm to review the coal inventory policies of the Company and as part of the consulting firm's review, coal inventory targets were recommended which were accepted by both the Company and the state regulators. These targets have been in effect for years, and are far below the Division's proposed inventory levels at the Utah coal plants. The Division is not suggesting that the Company reduce inventory levels to the targets agreed to between the Company and regulators, but instead reduce the inventory levels to the levels portrayed in ARL Exhibit 1, included in the Company's rebuttal testimony. The Division maintains the Company, in its direct case, should have raised with the Commission the high inventory levels at these plants and the Company's plans to exceed the agreed-upon targets.

The Division states the Company argues that if opportunities arise to purchase below market price coal, it will take advantage of those opportunities and that such actions are consistent with its coal policy and notes that this additional inventory benefits ratepayers approximately $12 million. The Division maintains the analysis only looks to the end of 2010. In addition, the Division asserts the Company has indicated it has no plans to reduce the inventory levels at those plants in the future. With the carrying charges caused by the high inventory levels, it will only take a year or two to eliminate any benefits associated with the high inventory level. The Division also maintains the benefits assumed by the Company are based on the assumptions in the exhibit, the market prices in particular, that the Company claims it would have to pay for substitute coal. It was the Division's position that the market prices were high and that they did not represent the cost at which the Company could actually purchase this additional coal.

During the hearings, an issue was raised involving corrections to the Division's calculation of the adjustment. The Division accepts in part the Company's correction, however disagrees with the Company's correction to remove the high ash coal from the calculated adjustment to reduce inventory levels. The high ash coal is included in rate base and should be included in the calculation since ratepayers are paying and will continue to pay a return on that coal for the indefinite future. These corrections should not divert the Commission's attention from the issue before it which is whether the high inventory levels at the Utah plants are justified both now and into the future which the Division argues they are not.

The Company recommends the Commission reject the Division's coal inventory adjustment because the Company's purchase of below market coal benefits Utah customers. The Company argues the Division alleges that the Company lacked a coal inventory policy, has overstated the current value of coal inventories acquired as a result of the Electric Lake Settlement, and that coal inventories at Utah plants should reflect 85 days of burn inventory. The Company testified that its coal inventory policy, which existed prior to the Electric Lake Settlement, set targets or recommendations for a range of coal inventory and that the inventory policy expressly provided for increasing inventory levels beyond the targets if the Company can procure coal at or below market prices as follows: " . . .Long term inventories will trend towards the 65-70 day target as high ash coal at the prep-plant is eventually shipped to the Hunter Plant. If there are opportunities in the future to procure Utah coal at below market (distressed) prices, the fuels department is prepared to pursue such purchases. There is sufficient storage capacity between the Utah plants and the prep-plant to store 4.57 million tons or 180 days of coal."

The Company asserts the Electric Lake Settlement of February of 2008 resulted in its acquisition of 1.5 million tons of coal at below market prices and was consistent with the May 16, 2007, policy cited above. The Company further testified the benefit of the Electric Lake Settlement, when netted for the carrying costs associated with additional coal inventory, results in a net benefit or savings of approximately $13 million.

The Company maintains the Division attempted to criticize the Company's current valuation of $46 per ton of the acquired coal. However, when cross examined on these points, the Division acknowledged that Argus Coal Daily and Coalcast Reporting Service have both valued Utah coal in the relevant time period at amounts equal to or greater than $46 per ton. The Company points out the Division acknowledged that it had not consulted with these pricing services, or for that matter, any other, in order to support his opinion that $46 per ton for Utah coal was unjustified.

The Company provides persuasive testimony that the increase in coal inventory which will allow the Company to avoid purchasing much higher market priced coal in the future is currently in the ratepayers best interest. This does not minimize the importance of a regularly reviewed, updated, and signed Company Coal Policy. The policy should provide an overall management strategy, flexibility to react to favorable market conditions, documentation requirements for deviations from the policy with an assessment of the costs and benefits associated with deviations, and tracking and monitoring requirements. In response to this policy, the Division should, during the course of its annual auditing, review inventory levels and compliance with inventory policies. While we do not accept the Division's adjustment on this issue the Division does raise important points regarding fuel inventory management. We direct the Division, beginning in 2011, to conduct an annual audit of the Company's fuel inventory management policies, procedures, and actual practices and provide a summary of its audit and associated findings to the Commission by no later than March 31 of each year for the previous year's activity.

c. Construction Work in Progress ("CWIP")

In its test year, the Company includes CWIP expense on cancelled projects. The Division recommends CWIP expense on projects cancelled for reasons outside the direct control of the Company should be recovered in rates, however CWIP on projects cancelled for reasons within the direct control of the Company should be written off and not be recovered in rates. In the future, if the Company wants recovery of CWIP on projects cancelled for reasons within the direct control of the Company, it should specifically make a request to the Commission in an appropriate general rate case or other relevant proceeding. The Division believes this is the first case in which this issue has been presented to the Commission. This adjustment reduces the Company's forecasted revenue requirement by about $0.2 million, of which about $0.1 million is allocated to Utah.

According to the Company, the Division's adjustment reflects cancelled projects including those which the Company initiated and determined could not be completed for various reasons including economic downturn, technical or process risks considered significant in completion of projects (i.e., within the Company's direct control). The expense is a small amount for a company this size. Therefore, the Company requests the Commission reject the Division's proposed adjustment.

During the course of the proceeding, the magnitude of this adjustment proposed by the Division was substantially decreased as the Company pointed out that many of the projects were outside of its direct control. The write-offs for the remaining projects are of small value. Furthermore, it may be in the ratepayers' interest that these projects are cancelled. For a company of this size and complexity, we find it reasonable for the Company to incur, on an on-going basis, a small value of write-offs associated with projects cancelled for reasons within the Company's control. Therefore we do not accept the Division's adjustment.

7. Summary of Revenue Requirement

Table 1 provides a summary of the Company's proposed Utah revenue requirement increase as filed in its direct case and all adjustments approved herein, for the future test period ending June 30, 2010. As shown, we approve a Utah revenue increase for the Company of $32.4 million.

TABLE 1: UTAH REVENUE REQUIREMENT CHANGE

Line No.	Description	Amount
1	**Change in Revenue Requirement in RMP Direct Testimony**	**$66,883,665**
	Cost of Capital:	
6	Allowed Rate of Return on Common Equity	(15,638,871)
	Undisputed Adjustments:	
3	Tax Settlement	(9,470,035)
36	Special Contract Revenue	(2,175,600)
39	Green Tag Revenue	(5,902,418)
57	Reverse Operations & Maintenance Budget Target	3,855,594
58	Salaries and Wages	(603,668)
59	Medical Insurance	(102,269)
60	Postemployment Benefits FAS 112	(232,394)
63	401(k) Contributions	(1,108,913)
69	Incremental Generation Operations and Maintenance	(1,766,562)
40	Environmental Settlement (PERCO)	(160,540)
45	Deferred Transmission Project AFUDC/PHFFU	(52,956)
49	Bridger and Trapper Mines	102,130
50	Plant Additions	308,662
51	Plant Retirements	(877,413)
52	Depreciation & Amortization Expense	(478,891)
53	Accumulated Depreciation & Amortization	976,527
54	Plant-Related Tax Update	15,636
2	Remove SMUD Revenue Imputation	2,063,202
15	Hydro Logic and Inputs - Motoring and Efficiency Loss	(108,545)
20	Wind Integration Error Correction	(500,288)
25 & 26	Expected Forced Outage Rates, Utah Gas plants	(412,516)
27	Wyodak Heat Rate Correction	(388,741)
74	Remove McFadden Ridge Transformer Double Count	(87,446)
55	Net Lag Days in Cash Working Capital	(99,347)
	Total Undisputed Adjustments	(17,206,789)
	Disputed Net Power Cost Adjustments:	
11	Uneconomic Model Operation	(738,175)
13	SMUD Contract Shaping	(218,980)
14	Biomass Non-Generator Agreement	(320,545)
21	Wind Integration Charges	(612,786)
22	Planned Outage Schedule	(140,898)
28	High Plains & McFadden Ridge Wind Start Dates	(197,643)
68	Qualifying Facility Contracts	485,382
31	BPA Peaking & Grant County Contracts	3,341,642
32	US Mag Reserves & Kennecott Generation Incentives	427,228
34	Coal Costs	(1,089,548)
	Total Disputed Net Power Cost Adjustments	935,679

Line No.	Description	Amount
	Disputed Labor-Related Expense Adjustments:	
79	Correction of Labor Calculation Error	1,380,821
42	Pension Administration	(155,709)
	Total Labor-Related Expense Adjustments	1,225,112
	Disputed Non-Labor Expense Adjustments:	
38	Uncollectible Accounts Expense	(1,617,194)
67	Remove Settlement Fees	(541,210)
46	Airplane Expense	(29,749)
47	Rent Expense	(118,100)
37	Generation Overhaul	(1,477,682)
	Total Disputed Non-Labor Expense Adjustments	(3,783,935)
	Total Change in Utah Revenue Requirement	**$32,414,860**

Line Number from Joint Issues & Position List, submitted by the parties on December 2, 2009.
Amount for No. 55 - Net Lag Days in Cash Working Capital calculated last.

C. REGULATORY POLICY ISSUES

The Company, Division and Office advocate regulatory policy changes or request guidance on specific issues.

1. Contingency Costs

In its direct and surrebuttal testimonies, the Division recommends for those wind projects for which the final project cost is not known at the time cost recovery is initially determined, the Commission adopt a policy to disallow contingency costs that are not already built into wind resource contracts. When final project costs are known, these full costs (assuming they are prudent) should then be included in rate base in future rate cases. The Division maintains this will ensure that any contingent event that occurs which is the responsibility of one of the Company's contractors and is defined and specified as such in the legal instruments between parties, does not result in costs to ratepayers.

The Company argues estimated contingency costs are reasonable and prudent and consistent with industry and construction practice and are therefore valid costs when setting rates based on a future test period. The Company states each wind construction project has the potential to incur unexpected costs. The fact that the majority of a wind project's costs is primarily spread over the turbine supply and construction agreements does not mitigate all the risk that there will be unforeseen circumstances or events that can impact a wind construction project's cost and/or schedule. The Company asserts contingency costs are certainly not "speculative" as the Division claims. In addition the Company disagrees with the Division's inference that contingency costs are included in contracts is incorrect. Contingency costs are not included in contracts because they are unknown, and therefore, contingency costs are not negotiated as part of the contract.

The Division argues ratepayers should not be required to pay the capital costs of speculative expenses that may or may not be incurred during the construction of a wind project. From information received in a confidential data request the Division indicates that contingency costs were only required for a couple of the Company's wind projects. The Division maintains the Company has sufficient experience in developing utility scale wind projects to plan for contingencies and to include terms and conditions in its contract negotiations which account for contingencies. In addition, there may be contingencies already covered in construction contracts, turbine supply agreements, or security provisions within the contracts for which the costs are the responsibility of the contractor and should not be passed on to ratepayers.

In response to the Company's testimony stating that contingency costs are not speculative, the Division provides the Association for the Advancement of Cost Engineering's ("AACE") definition of "contingency" which references uncertainty. The Division then reiterates its testimony that contingency cost is merely speculative and may never be realized. The Division believes the Company has the burden to account for and explain any contingency costs that go into rates for future wind projects.

The issue before us is not whether it is appropriate to include contingencies in cost estimates for wind plants. Rather, if contingencies are included in forecasted wind project costs whether these contingency cost estimates should be included in rates established before the project is completed and the final project cost known. We agree in part with the Division that the Company as a whole is gaining experience in developing utility scale wind projects. This experience will help the Company identify contingencies and include terms and conditions in its contract negotiations to account for contingencies. We also agree with the Division that any contingency costs passed through to ratepayers should be carefully reviewed prior to inclusion in rates and be subject to exclusion if imprudent. We also note that the Company's capital budget in any year includes many projects of various sizes, some which may end up under budget and some which may end up over budget, and many of which likely also include contingency costs.

In RMP-RR Cross Exhibit 2, the Company provides various definitions of contingency. Based upon the AACE Cost Engineering Terminology in Recommended Practice No. 10S-90, contingencies are typically estimated using statistical analysis or judgement based on past asset or project experience. Based upon the Project Management Institute's Guide to the

Project Management Body of Knowledge (ANSI/PMI 99-01-2008) contingency reserves may be a percentage of the estimated cost, a fixed number, or may be developed by using quantitative analysis methods. This standard further indicates, "As more precise information about the project becomes available, the contingency reserve may be used, reduced or eliminated." With this information we conclude that some may argue the best estimate for a project requires inclusion of a contingency amount. In addition, the latter definition implies that a contingency amount is not static but rather should be adjusted as more information becomes available. Rather than accept the Division's proposal, which is limited solely to wind plants, we find the definitions above should aid the Division in conducting its prudence review of contingency costs in cost recovery cases in which a yet to be finished project is included.

The Division also recommends the Commission require the Company to submit a notification letter to the Commission at the time each wind plant comes in service. The Company disagrees and argues as a matter of policy, the Commission should not require a notification letter each time the Company places a capital asset in-service. The volume of notifications would be burdensome on the Company and the Commission staff. In addition, the Company provides the Commission and Division with routine business updates and should there be a question to the Company's current activities as it relates to wind projects, the Division simply needs to ask the Company.

Contrary to the Company's response, the Division is only requesting notification at the time each wind plant comes in service – not every capital asset. We find this request reasonable and direct the Company to provide the Commission and the Division a notification of wind plant in-service letter within 30 days of a wind facility's designation as in-service.

The Division also recommends the Commission require the Company to report detailed accounting of its capital wind projects rather than lump sum capital costs in order for the Division to complete a full prudence review of future wind projects. The Company maintains it has provided sufficient detail for the Division to complete a full prudence review of resource economics associated with wind-powered generation resources. Following completion of the rate case, the Company is willing to meet with the Division to address any issues relative to the information provided for purposes of reviewing the evaluated cost of energy associated with the Company's owned and contracted wind resource acquisitions. We find the Company's offer reasonable, however, we believe this meeting should be open to all parties, the accounting data should ultimately be provided in any cost recovery application rather than through a data request, and a summary of the outcome of the meeting should be provided to the Commission. We direct the Division to arrange such a meeting at its and the Company's convenience.

Finally, the Division recommends the Commission review the Company's strategy of building 99 megawatt wind farms adjacent to each other as separate projects in order to avoid the solicitation process required in Oregon for major resource additions. The Company disagrees with the Division and maintains its strategy is to add supply-side resources in an economic fashion. The Company offers to meet with the Division after completion of the rate case to help them further understand the Company's strategy with respect to resource acquisition decisions and the circumstances that led the Company to pursue each and every wind resource in its portfolio, regardless of size. We find the Company's offer reasonable, however, we believe this meeting should be open to all parties. We direct the Division to arrange such a meeting at its and the Company's convenience.

2. Hedging Practices

The Division provides detailed testimony summarizing its investigation of the Company's current natural gas and electricity hedging policies and practices. The Division provides several recommendations which we do not recount or address here. We will consider the Division's testimony, recommendations and its Blue Ridge Consulting Report in the context of Docket Nos. 09-035-15 and 09-035-21.[11]

IV. COST OF SERVICE AND REVENUE SPREAD

A. INTRODUCTION

The Company provides an electronic model which follows the FERC Uniform System of Accounts. The FERC account detail is also presented in financial reporting and the development of test year revenue requirement. The Division, UAE and UIEC present cost-of-service studies using the Company's model. These studies differ from the Company's in the formation of some allocation factors and the application of factors to specific accounts.

In our May 7, 2009, order in Docket No. 08-035-38, we approved a stipulation which created a work group on the Company's cost-of-service model. The purpose of this work group was for interested parties to discuss the Company's cost-of-service model addressing its mechanics rather than the assumptions utilized. The Company agreed to develop instruction

---

[11] Docket No. 09-035-21, "In the Matter of the Natural Gas Price Risk Management Policies and Procedures of Rocky Mountain Power."

manuals for operating specific sections of the model, to provide training on the model to all interested parties requesting such training and to provide additional documentation and other reasonable means of facilitating easier use of the model. Further, the parties agreed to discuss and negotiate in good faith at least the following issues, without limitation: the scope of any necessary instruction manuals; the relationship between the Company's Jurisdictional Allocation Model ("JAM") and the cost-of-service model and consistency between the two models; potential alternative cost-of-service models; and potential changes and improvements to the current cost-of-service model. These meetings were held in June, July and August of 2009, and the Division hired a consultant to examine the model and provide recommendations on the model which are discussed in this case.

B. COST OF SERVICE

1. Reliability of Load Sample Data

Costs are allocated to customer classes, in part, based on customer class loads coincident with system monthly peaks. Since certain customer classes do not have demand meters, e.g., residential, small commercial and irrigation customers, the Company selects a sample of these customers, installs load research meters at the customer's premises, records the demand data, and extrapolates this data to the entire residential, small commercial and irrigation customer populations. This procedure is used to estimate the hourly loads, including contributions to monthly system peaks, of the entire class and to develop cost allocation factors.

The Company testifies the sample residential customers were drawn at the time the sample design was prepared, in the very early 1990's. The Company testifies the sample data employed in its cost-of-service study was collected throughout the specified base year, the 12 months ending December 2008.

The Company explains it uses stratified random sample designs rather than simple random sampling because it is more cost effective. Each sample is designed to provide estimates of load that fall within plus or minus 10 percent of the actual load, nine out of ten times.

The Company provides evidence demonstrating the residential load research sample reasonably reflects the usage of the residential class for the base year. This evidence shows the difference between sample annual estimated energy and annual billed energy was 4.7 percent, 0.089 percent, 0.089 percent for 2006, 2007 and 2008, respectively. Further, the Company provides demand curve analysis of the sampled data which the Company argues shows growth in the afternoon and evening residential loads, consistent with the increased penetration of central air conditioning. Thus, the Company contends the residential load research sample compares acceptably to known variables, i.e., billing data.

The Company testifies its irrigation customer sample is not drawn from the entire irrigation class but rather is drawn from those customers who had actively irrigated in the previous two years. The purpose of this load research was to develop a load shape for actively irrigating customers to produce load estimates of active irrigation. Thus, when these estimates are expanded by the total population of the irrigation class, the results are overstated. These load estimates are then ratioed down to match billed energy for the period.

The Division argues the estimates resulting from the Company's load research program do not meet the Public Utility Regulatory Policies Act precision standard. Monthly differences between estimates of class energy and actual billed energy exceed the stated confidence level. The Division states this could be due to many factors. The Division does not accept the Company's comparisons of annual actual versus estimated energy as a basis for suggesting the samples are sufficiently accurate. Rather, the Division argues monthly differences are important because it is monthly load data derived from the load samples that are used in cost allocation. The Division suggests the sample design can be altered and the stratification process changed to improve the Company's method. The Division recommends a working group would be appropriate to study the issue further.

The Office testifies the load data for the irrigation class should not be relied upon to support a rate change above the jurisdictional average. The Office argues there is a very large disparity between estimated and actual usage for the irrigation class.

UIEC argues the load research samples used to estimate the loads of Schedule 1, Schedule 6 and Schedule 23 are very old and do not represent the current characteristics of these customers in Utah. In addition, the load data for classes is not properly adjusted for weather conditions to reflect true "peak making" weather. Therefore, UIEC contends, the loads of weather-sensitive customers such as residential and small commercial are not properly reflected in cost allocations. UIEC and UAE both question the load research data as a source contributing to the gap between the Company's forecast of the sum of class peaks and its forecast of Utah jurisdictional peaks.

We agree with the Division, load sampling and associated issues are appropriate for a working group to examine. We direct the Division to form a working group to examine the issues raised by the Division and other parties.

2. Sum of Class and Jurisdictional Peak Load Forecasts

Several parties testify the sum of the class loads developed for the cost-of-service study do not equal the Utah jurisdictional load which is the basis, in part, for allocation of total Company costs to Utah. In rebuttal testimony, the Company contends at least three reasons, unrelated to sample data, explain the differences between the sum of the class loads and the jurisdictional load: 1) the method used to calculate forecast class load data, 2) losses, and 3) the exclusion of certain customer loads.

The Company describes the method it used in its direct testimony for forecasting class load data which includes alignment of the historic calendar with the forecast calendar. In rebuttal testimony, the Company asserts this method of aligning the historic calendar to the forecast calendar might be distorting loads. Further, the Company asserts, this method causes an exaggerated disparity between forecast jurisdictional loads and forecast class loads. Therefore, in rebuttal, the Company produces a second cost-of-service study for this case. In this study, the Company removes the alignment of historical dates to forecast dates. After the base year estimates have been adjusted to reflect forecast energy levels, the class load summaries are based on the dates and times of the historical system peaks. The Company testifies this change reduces the difference between the sum of class loads and the jurisdictional loads from 9 percent to 2 percent.

Due to the late presentation of the cost-of-service study changes, the Division states it was precluded from thoroughly analyzing the Company's rebuttal changes. The Division's preliminary observations leads it to conclude the new information is potentially unreliable and recommends the Commission not accept this study.

The Office states the Company's new cost-of-service study introduces 12 new monthly coincident peaks, 11 of which differ from the Company's initial cost-of-service study by one hour (May 2010), several days, and as many as 29 days, 8 hours (October 2009). Further, while the April 2010 peak date and hour are the same for the test year in the application and for 2008 in the rebuttal study, the class contribution to the April coincident peak changes without any logical explanation.

The Office argues the Company's rebuttal cost-of-service study class 12 coincident peaks are based on 2008 actual dates and times of the peaks, rather than test year forecasted peak dates and times, and this change is unsupported by any analysis to confirm that 2008 was a particularly representative year in terms of the timing of peak loads or of the coincidence of Utah and system peaks. Further, the Office testifies: "The most troublesome issue is that all the demand allocators, not just those derived from the class contribution to system peak demand, changed from the original filing to RMP's rebuttal."

The Office argues the Company's rebuttal cost-of-service study was untimely, unsupported with proper evidence, and produces large, unexplained swings in class cost-of-service results. The new study is a sweeping and material revision and not simply the correction of an error and should be rejected. In its post-hearing brief, the Office renews its Motion in

Limine, requesting the Commission decline to consider evidence offered by any party in pre-filed written testimony, in oral summaries, or in oral reply or responsive testimony, consisting of or relying upon the following: Revised cost-of-service analysis and new class cost-of-service studies offered in the Company's rebuttal testimony.

UAE argues the testimony in this case demonstrates the Company's initial cost-of-service method produces inaccurate results in projecting peak responsibility for classes whose loads are estimated based on samples. UAE points to the Company's initial filing wherein there is a difference of approximately 9.6 percent between the jurisdictional demand allocated to Utah and the sum of the class demands used to allocate costs to customer groups. UAE gives credit to the Company for responding to intervenor direct testimony on this issue by investigating the data and results. By correcting the error caused by the mismatch between actual peak-day class responsibility and peak-day responsibility assumed in the Company's initial methodology, the Company was able to reduce the gap between Utah's peak-day responsibility and the sum of peak-day class responsibility to about 2 percent. Although the remaining 2 percent is still cause for concern, UAE argues the Company's rebuttal cost-of-service study is a significant improvement.

UAE requests the Commission accept the Company's corrected approach, and then direct the parties to re-investigate load measurement issues after the conclusion of this case. Such investigation should include, among other things, reconsideration of the Company's 2002 decision to cease calibrating class loads to jurisdictional loads. That decision was supported by customer groups who benefitted from the decision but was not approved by the Commission or understood or evaluated by customer groups who UAE states were harmed by it.

UAE contends the argument that parties had insufficient time to verify the Company's new method rings hollow, particularly given these same parties failed to ever verify the initial, incorrect method that produced serious errors in assigning peak load responsibility in this case, as it has done for several cases. UAE continues that it also rings hollow in that these parties did not request more time to validate the correction. It is unreasonable for a party to argue that the Commission should utilize an admittedly flawed approach because some parties elected not to spend or request the time and effort necessary to confirm what the Company and others have clearly demonstrated, i.e., the Company's initial approach seriously understates the contribution to peak day demand by classes whose loads are not measured.

UIEC argues neither the originally-filed class load data nor the revised class load data are sufficiently accurate for use in allocating costs. Therefore, for the purposes of this case, the rates established in Docket No. 08-035-38 are presumed, under the filed rate doctrine, to be just and reasonable. The current case addresses the Company's application for an increase in those rates. Based on the record in this case, the Commission should order that an equal percent of any increase in revenue requirement be assigned to each rate schedule.

The Company recommends the Commission reject parties' requests to exclude the rebuttal cost-of-service study because the reasons used to support such requests are unfounded. The Company argues the method on which the class loads in the rebuttal cost-of-service study are based is not overly complicated and is the same method the Company used in prior rate cases with historical test periods.

For the reasons stated by the Division and Office, we give only partial weight to the new study in our decision on spread in this case. Our decision on spread is shown in Table 4. However, we recognize the issues raised must be addressed going forward. We direct the Division to convene a work group to examine the Company's load forecast methods, both for jurisdictional and sum of class loads, to revisit the "recalibration" issue, to examine how weather normalization should be treated in peak load forecasts.

3. Generation and Transmission Classification and Allocation

Consistent with the Commission's approved classification and allocation of generation and transmission costs, the Company classifies these costs as 75 percent related to demand and 25 percent related to energy. The Company generally allocates demand-related costs based on each load's contribution to the sum of the12 monthly system coincident peaks and allocates energy-related costs based on annual energy requirements. As discussed below, the Revised Protocol method includes deviations from these classification decisions and allocation methods for the purpose of calculating revenue requirement.

The Company proposes the Commission continue to use the 75/25 demand/energy classification of generation and transmission plant for three reasons. This classification recognizes the design capability of meeting both peak demand and to generate lower cost energy. Second, the Commission has previously decided that this classification is reasonable. Third, no other thorough analysis has been submitted that supports a change from the current classification split.

The Office and UIEC propose alternative classification definitions or allocation methods for generation or transmission that deviate from the approved methods used by the

Company. These parties argue their proposals are superior to the current methods for a variety of reasons. These parties also maintain that consistency between interjurisdictional and class methods is not necessary, particularly since the interjurisdictional method results from a multi-state compromise. The Division and UAE, like the Company, oppose the proposals of the Office and UIEC, and support the prior Commission decisions on maintaining consistency between interjurisdictional and class allocations.

We find the Company's classification and allocation methods for generation and transmission costs are generally consistent with our prior decisions. Contrary to some assertions, these methods have been supported in the past by analysis, including stress factor analysis. Neither the Office nor UIEC produces this type of analysis to demonstrate the current methods are no longer reasonable. Any party who would like to propose an alternative to the approved methods must provide analysis to demonstrate the proposed method is also appropriate and viable at the interjurisdictional level. This analysis must include a level of detail to determine the impacts to Utah and other states in the PacifiCorp system of a proposed change in classification and allocation methods.

4. Classification of Wind Generation Costs

The Company classifies wind generation costs as 75 percent related to demand and 25 percent related to energy. This is consistent with the classification of wind resource cost in both the Revised Protocol and Roll-In methods of interjurisdictional cost allocation.

The Division argues wind resource costs should be separately identified in the accounting system, so as to break it out from gas resource costs. Further, the Division contends wind resources should be classified as 100 percent related to energy, and zero percent related to demand. The Division makes these changes in its cost-of-service study. The Division contends the Company's approach to wind resource cost allocation does not recognize the unique nature of a wind resource, i.e., it is both non-dispatchable and uncertain, which makes it appropriate to classify wind resources as 100 percent energy.

UAE proposes to classify wind resource costs as 20 percent demand-related and 80 percent energy-related to be consistent with the Company's investment decisions. UAE argues a 100 percent energy classification is inconsistent with the Company's IRP which assigns wind resources a 20 percent capacity value.

Pending further study and understanding, UIEC recommends the fixed costs of wind resources continue to be allocated in the same manner as other generation resource costs. UIEC argues there is uncertainty associated with the nature and cost of wind as an electricity resource and therefore it is premature to classify all wind resources as 100 percent energy related. UIEC recommends further analysis as additional costs become apparent. The question of who should bear these costs must be confronted and carefully evaluated.

UAE, the Division and the Office all argue the allocation of renewable energy credits and green tag revenues should be consistent with the cost allocation of wind resources.

We concur with the Division and direct the Company to separately identify wind resource costs in its accounting system. We concur with the Company to classify wind resource costs as 75 percent related to demand and 25 percent related to energy as is done for interjurisdictional cost allocations.

We affirm our commitment to having a consistent basis for allocating the Company's shared system costs to each state in the PacifiCorp utility system and among the classes within Utah. We may make exceptions related to treatment of the MSP stipulation adjustments which we address below. Other than treatment of MSP stipulation components, parties recommending changes to cost allocations for class cost of service purposes must provide analysis regarding the appropriateness of these changes for interjurisdictional cost allocations and provide an estimate of the impact to Utah and the other states of any proposed change and an assessment of the likelihood such a change could also be made at the interjurisdictional level.

5. Consistency Between Interjurisdictional and Class Allocations

The Division emphasizes the allocation factors used to determine Utah’s revenue requirement in the Company’s interjurisdictional model reflect important information regarding the classification of costs. The Division then identifies certain allocation factors used in the Company’s class cost-of-service study which do not reflect the classification decisions made in the interjurisdictional model. As examples of these inconsistencies, the Division cites the treatment of the costs associated with the combustion turbines, Cholla generation and the rate base item, materials and supplies. The Division recommends the Commission appoint a work group to review, update and revise as necessary the allocation issues existing between the interjurisdictional and class cost-of-service models.

We agree there are inconsistencies between the allocation factors used in Company’s interjurisdictional and class cost-of-service models. We find these inconsistencies must be addressed and therefore accept the Division’s recommendation. The goal of this work group is to produce a document comparing all interjurisdictional and class cost-of-service allocation factors, for both the Roll-In and Revised Protocol methods. Factors for which consensus cannot be achieved will be documented and explained. This type of information was provided to the Commission for the interjurisdictional model with the approval of the MSP stipulation in Docket No. 02-035-04.[12] We direct the working group to provide a similar document to be filed with the Commission by no later than November 30, 2010. As direction, we reiterate our March 4, 1999, Report and Order in Docket No. 97-035-01[13] in which we addressed allocation issues and stated:

> " . . . The very basis for task force evaluation of allocations must be that all functionalization, classification, and allocation decision are correct. This means that the decisions flow from an acceptable characterization of the engineering economics of integrated, single system operation. We expect the task force to assure us that this is so. We also want to insure that these fundamental cost-of-service decisions are applied consistently at interjurisdictional and class levels. The task force therefore should address changes to interjurisdictional allocation method that may be necessary. Moreover, we see no reason why the added stop of functionally unbundling cost of service should alter the apportionment of cost of service to classes that results from a properly conducted, but not unbundled, cost-of-service study. In our view, these presumptions must hold unless good and sufficient cause shows otherwise."

6. Allocation of Firm Non-Seasonal Purchases

The Company classifies firm non-seasonal purchases as 75 percent related to demand and 25 percent related to energy which is the same classification it uses in interjurisdictional cost allocations. The Company allocates each month's cost separately based on class coincident peak and kilowatt-hour usage in that month.

The Office opposes this classification claiming it is inconsistent with the classification of generation plant and understates the energy-related portion of firm non-seasonal purchases. The Office recommends classifying a greater percentage of firm non-seasonal

---

[12] Docket No. 02-035-04, "In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues."

[13] Docket No. 97-035-01, "In the Matter of the Investigation into the Reasonableness of the Rates and Charges of Pacificorp, Dba Utah Power & Light Company."

purchases as energy. The Office states fixed generation plant is classified as 75 percent demand-related and 25 percent energy-related while all fuel expense is classified 100 percent energy-related. The Office argues this essentially means 62.5 percent of generation plant is classified as energy, assuming 50 percent of the total cost is fuel, yet only 25 percent of firm non-seasonal purchases are classified as energy. The Office testifies energy charges are 83 percent of total short-term firm and long-term firm contract costs in the Company net power cost study.

The Company argues the Commission should reject the Office's recommendation to increase the energy-related portion of firm non-seasonal purchases because it would cause sales for resale revenue and purchased power expenses to be allocated differently due to the fact that sales for resale revenue would be allocated inconsistently with the cost of the resources supporting those revenues.

We approve continued use of the Company's classification for firm non-seasonal purchases because it is consistent with both interjurisdictional cost allocation and with treatment of firm non-seasonal wholesale sales. Any party proposing a change to this classification must address these two issues, providing analytical support a change is reasonable in both instances and to provide comprehensive impact analysis of the proposed changes.

7. Classification and Allocation of Distribution Facilities

a. Substation Equipment, Primary Lines, Line Transformers and Secondary Lines

The Office recommends the Commission order the Company to implement improvements in its next cost-of-service study to meet the following goals: allocate demand-related distribution costs based on class contribution to loads in the many high-load hours that determine the duration of peak loads; and revise the monthly weights for the primary distribution allocator to more reasonably reflect monthly distribution demand.

The Office testifies the Company's cost-of-service study allocates the costs of substation and primary lines based on weighted monthly coincident distribution peaks. The coincident distribution peak is the simultaneous combined demand of all distribution voltage customers at the hour of the distribution system peak. These monthly values are weighted by the percent of substations that achieve their annual peak in each month of the year. The Company allocates the costs for line transformers and secondary lines based on weighted non-coincident peaks, where the weighting adjusts for the diversity of load on shared distribution equipment.

The Office asserts allocation of these distribution costs does not reflect cost causation for the following reasons: 1) It overlooks many of the ways that periods of high energy use drive distribution investment; and 2) the monthly weighting factors used in deriving the allocator for substations and primary feeders are not cost-based. The Office maintains the Company acknowledges that energy (i.e., duration of peak) affects distribution costs by its acknowledgment that duration of peak, load cycle, and on-peak energy are all cost-causal factors. The Office provides several examples supporting its contention that the duration of high load affects distribution investment and outage costs.

The Office further maintains the Company's distribution design guidelines indicate that periods of high energy use and duration of peak load are driving factors in distribution costs as they identify a number of ways in which expected energy use, especially in hours close to peak in load or time, affects both the design standards and investment. The Office believes the distribution weighting factors are invalid because weighting each month by the number of substations that peak in that month does not reflect cost causality. Monthly weighting factors should recognize the size of individual substations and the effect of multiple peaks and the duration of peaks on substation sizing.

The Company recommends the Commission continue to endorse its use of the current classification and allocation factors for distribution costs and states parties present no evidence supporting a change to distribution classification and allocation factors. The Company argues the current classification and allocation used for distribution costs have been used for the past 19 years, and are supported by the Distribution Cost Allocation Study; a comprehensive study that was vetted for many years and reviewed in multiple cases. The Company testified that the projected peak load, including growth, is the key cost driver of substation equipment and primary lines, and that as such, substation equipment and primary lines should continue to be classified as 100 percent demand-related.

The Company further testifies it has reviewed its current distribution construction standards and found them to be consistent with the current allocation methodology. In contrast, the Company maintains the Office presented no comprehensive study, relied on twenty- to thirty-year outdated design guidelines, and, in some cases, presented incomplete and therefore unreliable evidence as support for a change.

Based upon the history of this issue, past support for the Distribution Cost Allocation Study, and the Company’s testimony regarding a review of its construction standards, we are persuaded by the Company’s testimony that the allocation of these distribution costs based upon demand does reflect cost causation in this case. We accept the Company’s position for the reasons noted above.

b. Service Drops

The Office recommends the Commission direct the Company to conduct a study of shared services to determine the split of the cost of service drops serving single and multi-family residential dwellings. In addition, the Office recommends that the Commission order the Company to implement improvements in its next cost-of-service study to recognize the sharing of service drops by residential customers in multi-family dwellings.

The Office states the cost of service drops are classified as customer-related and allocated using the average service drop cost (for each rate schedule) times the number of customers. The Office maintains that the allocation factor does not reflect sharing of service as it assumes each residential customer requires its own service line and ignores the sharing of services by customers in multi-family buildings. Therefore, the Commission should direct the Company to conduct a study of shared services to determine the split of service drops by single and multi-family residential dwellings.

The Company argues it allocates service drops using a single service per customer because Company records do not contain data regarding the number of customers per service drop and there has been no business reason to maintain such data. However, if the Commission determines this information is needed, the Company requests that a public process be undertaken to complete a shared services study and that the cost of such a study receive prior approval from the Commission. The Company estimates that a study could be expensive and time consuming since it would entail a thorough physical survey of Utah residential and general service customers in order to determine and classify the types of shared services that are in place. Because such a study has never been performed, the Company is unable to estimate its cost.

We observe a change in the allocation method for service drops would result in the shift of costs from one customer group to another. In this instance, however, we received no testimony from the Division, the state's impartial investigator. Absent such testimony we do not accept either party's recommendation. Rather we direct the Division to conduct a comprehensive analysis of this issue, including a history and magnitude of the issue and recommended solutions to address the issue which may provide a reasonable outcome.

8. Treatment of Income Taxes

In the interjurisdictional allocation model, income taxes are calculated based on taxable income. In its class cost of service study, the Company allocates to classes Utah's income taxes based on relative rate base rather than taxable income. UAE recommends income taxes be calculated on taxable income, similar to the approach taken in the interjurisdictional model.

The Company's approach mixes income taxes incorporating the effect of the change in revenue requirement for a specific class with the earned income and rate base components of the class. The approaches of both the Company and UAE can be used to determine the change in revenues required to achieve an allowed rate of return, and moreover, both will provide the same revenue change. However, the Company's approach tends to overstate the rates of return for classes earning above Utah's overall earned rate of return and understates the rates of return for classes earning below Utah's overall earned rate of return. The use of taxable income to calculate income taxes was recently ordered in the recent rate case for

Questar Gas Company, Docket No. 07-057-13.[14] Therefore we accept UAE's proposal as a matter of policy to calculate income taxes based on taxable income in the class cost-of-service study.

9. Treatment of the MSP Rate Mitigation Cap

In its cost-of-service study, the Company uses as inputs the Utah results obtained from the Revised Protocol method for interjurisdictional allocation. The Company then lowers the rate of return on rate base in the Utah cost-of-service study from what the Company is otherwise allowed, thereby reducing the Utah revenue required under the Revised Protocol method to that required by the MSP stipulation. The effect of the Company method is to allocate to classes on the basis of relative rate base the revenue reduction necessary to satisfy the MSP Stipulation. Both the Division and UAE recommend the revenue decrease from Revised Protocol required by the MSP Stipulation be applied to only the production function, since the differences between the Revised Protocol and Roll-In methods are directly related to the production function.

There can be as many interpretations of a stipulation as there are signatory parties. However, the MSP Stipulation defines Utah's revenue requirement to be the lesser of Utah's revenue requirement calculated under the Roll-In method multiplied by a rate mitigation cap and Utah's revenue requirement calculated under the Revised Protocol method multiplied by

[14] Docket No. 07-057-13, "In the Matter of the Application of Questar Gas Company to File a General Rate Case."

a rate mitigation premium.[15] We find the appropriate inputs into the class cost-of-service study must be consistent with the MSP Stipulation.

We note every year since the MSP Stipulation was approved in 2004, Utah's revenue requirement has been calculated under the Roll-In method multiplied by the rate mitigation cap. Thus the Roll-In method, not the Revised Protocol method, has been and so far continues to be the basis for Utah's revenue requirement under the MSP Stipulation. Therefore, instead of treating the reduction in Utah's revenue requirement necessary under the MSP Stipulation relative to the Revised Protocol method, as recommended by the parties in this proceeding, so long as Roll-In is the basis for Utah's revenue requirement under the MSP Stipulation, what must be treated is the increase in Utah's revenue requirement under the MSP Stipulation relative to the Roll-In method.

The MSP Stipulation requires the rate mitigation caps and premiums be applied to revenue requirement, which is equivalent to cost of service, including both expenses and rate base. Therefore we reject the Company's approach which is equivalent to allocating based on relative rate base alone. We also reject the Division's approach which allocates the revenue difference required by the MSP Stipulation using a Utah generation factor. The differences between the MSP Stipulation and the Revised Protocol and Roll-In methods are related to cost of service, not a single, specific allocation factor.

We recognize, as do the Division and UAE, the differences between the Revised Protocol and Roll-In methods are related to the unbundled production function. Therefore, we

---

[15] The MSP Stipulation also specifies the values of the rate mitigation caps and premiums on a fiscal year basis through March 31, 2014.

conclude the increase in Utah's revenue requirement under the MSP Stipulation relative to the Roll-In method must in the future be allocated to classes based on relative costs of service for the unbundled production function.

10. Summary

In summary, we order the formation of a working group or working groups led by the Division to address the following: load research methods and associated issues; peak hour load forecasting methods at the interjurisdictional and class levels; consistency of allocation factors between the JAM and class models. Additionally, we direct the Division to perform a comprehensive analysis of shared service drops. We direct the Division to file the results of these work groups and its recommendations on these issues by November 30, 2010.

C. RATE OF RETURN INDEX

Cost-of-service studies can be summarized and presented by the ratio of the earned rate of return of a particular rate schedule to the earned rate of return of the system, also known as the rate of return index. The results of the parties' cost-of-service studies are presented in this format in Table 2 below.[16]

Despite the differences regarding the calculation of income taxes and forecast of system peak load, i.e., the difference in the Company's direct and rebuttal cost-of-service studies, the parties' cost-of-service studies indicate a somewhat similar set of results. We

[16] UAE and UIEC perform sensitivity analysis of the Company's direct testimony cost-of-service study regarding measurement of class loads, and peak loads of Schedule 1, 6, &23, respectively, which are not presented here. The results are similar to the range of results presented in Table 2. UIEC results for alternative classification and allocation methods are also excluded given our decisions on cost of service.

observe in all studies the residential class and small, large and over 1 megawatt general service classes all perform within or above a 10 percent band around the system average return. We

TABLE 2: RATE OF RETURN INDEX FROM COST OF SERVICE STUDIES

Schedule Description	Sch. No.	RMP Direct	RMP Rebuttal	DPU Direct	DPU Rebuttal	UAE Direct	UAE Rebuttal
Residential	1, 2, 3	1.16	1.00	1.15	1.15	1.11	0.99
General Service - Large	6, 6A	1.03	1.11	1.05	1.05	1.01	1.06
General Service - Over 1 MW	8	0.94	1.02	0.95	0.94	0.96	1.01
Street & Area Lighting	7, 11, 12	2.30	2.31	2.07	2.11	1.72	1.72
General Service - High Voltage	9, 9A	0.69	0.78	0.71	0.69	0.82	0.89
Irrigation	10, 10A	0.43	0.43	0.43	0.41	0.62	0.63
Traffic Signals	15.1	0.82	0.88	0.82	0.81	0.87	0.91
Outdoor Lighting	15.2	5.65	5.74	4.51	4.65	4.35	4.28
General Service - Small	23	1.01	1.13	1.02	1.02	1.02	1.10
Mobile Home Parks	25	1.17	1.00	1.14	1.15	1.12	0.99
Customer A	SpC	0.23	0.34	0.26	0.31	0.47	0.57
Customer B	SpC	(0.50)	(0.24)	(0.47)	(0.33)	0.03	0.26
Customer C	SpC	0.52	1.21	0.56	0.59	0.66	1.17
Total Utah		1.00	1.00	1.00	1.00	1.00	1.00

observe in all studies the high voltage general service, irrigation classes and, in all but one study, traffic signal systems classes perform below a 10 percent band around the system average return. We observe in all studies the street, area, and outdoor lighting perform significantly above the 10 percent band around the system average return. This leads to our conclusion a non-uniform spread of revenues is supported by the record. The parties use these cost-of-service results as a guide to forming their revenue spread proposals to which we now turn.

D. REVENUE SPREAD

1. Positions of the Parties

Parties' revenue spread recommendations are presented in Table 3 below. The proposals are consistent with each party's revenue requirement assumptions.

a. Company

In rebuttal testimony the Company proposes a range of increases from 2.82 percent to 4.85 percent for its recommended revenue increase of $54.9 million. Specifically, the proposed rate increases are approximately as follows: Residential (average of Schedule Nos. 1, 2, and 3) – 3.85 percent; Schedule No. 23 – 3.86 percent; Schedule No. 6 (average of Schedule Nos. 6, 6A, and 6B) – 3.85 percent; Schedule No. 8 – 3.85 percent; Schedule No. 9 – 4.85 percent; Irrigation (average of Schedule Nos. 10 and 10 TOD) – 4.85 percent; Lighting (average of Schedule Nos. 7, 11, and 12OL/15.1) – 2.9 percent. All other schedules receive an increase of between 3.85 percent and 4.85 percent. The Company maintains its proposal is designed to reflect cost of service while balancing the impact of the rate change across customer classes and, therefore, is reasonable and should be adopted. While several alternatives were proposed, the Company believes its proposal is a balanced approach which takes everyone's interests into consideration and is consistent with recent outcomes in Utah.

Regarding the revenue spread proposals of other parties, the Company states, in general, these proposals fall into two groups: those who advocate for strict adherence to the class cost-of-service results (Office and Wal-Mart) and those who recommend using the results as a guide in determining rate spread (Division, UAE, UIEC, and Kroger). While within each of these groups there are differences, the Company believes, as reflected in its revised rate spread

TABLE 3: REVENUE SPREAD PROPOSALS

Schedule Description	Sch. No.	RMP	DPU	OCS	UAE	UAE	UAE	UAE
Proposed Revenue Change ($ million)		**$55.0**	**$16.7**	**($11.0)**	**$55.0**	**$8.5**	**($0.9)**	**($5.9)**
Residential:								
Residential	1, 3	3.85%	0.00%	-2.00%	4.13%	0.76%	0.09%	-0.27%
Residential - Option TOD	2	4.06%						
Residential - Mobile Homes	25	3.85%	0.00%	-0.66%				
Total Residential								
Commercial & Industrial & OSPA:								
GS - Distribution	6	3.85%						
GS - Distribution - Energy TOD	6A	3.85%						
GS - Distribution - Demand TOD	6B	4.34%						
Total Schedule 6			0.57%	-0.66%	3.47%	0.13%	-0.55%	-0.90%
GS - Distribution > 1,000 kW	8	3.85%	2.25%	0.00%	4.13%	0.76%	0.09%	-0.27%
GS - High Voltage	9	4.85%						
GS - High Voltage - Energy TOD	9A	4.85%						
Total Schedule 9			5.85%	2.50%	4.47%	1.09%	0.41%	0.05%
Irrigation	10	4.86%						
Irrigation - TOD	10A	4.72%						
Total Schedule 10			11.91%	-0.79%	4.47%	1.09%	0.41%	0.05%
Electric Furnace	21	3.85%						
GS - Distribution - Small	23	3.86%	1.02%	-0.66%	4.13%	0.76%	0.09%	-0.27%
Back-up, Maintenance, & Supplementary	31	4.83%						
Special Contracts		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Commercial & Industrial & OSPA								
Public Street Lighting								
Security Area Lighting	7	2.85%	0.00%					
Street Lighting - Company-Owned	11	2.84%	0.00%					
Street Lighting - Customer Owned	12	2.82%	0.00%					
Metered Outdoor Lighting	15.1	3.06%	0.00%					
Traffic Signal Systems	15.2	3.42%	3.98%					
Security Area Lighting - Contracts		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Street Lighting - Contracts		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Public Street Lighting								
Total Sales to Ultimate Customers		3.73%	1.13%	-0.75%	3.72%	0.58%	-0.06%	-0.40%

UAE's "Proposed Revenue Changes" are only illustrative for revenue spread proposals.

proposal, the application of cost of service as a guide in determining rate spread will best achieve the goals of reflecting cost of service while minimizing rate impacts across customer classes.

b. Division

In surrebuttal testimony the Division proposes a range of increases to the various rate schedules from 0.00 percent to 11.91 percent. Specifically, the proposed rate increases are approximately as follows: Residential Schedule No. 1 – 0.00 percent; Schedule No. 23 – 1.02 percent; Schedule No. 6 – 0.57 percent; Schedule No. 8 – 2.25 percent; Schedule No. 9 – 5.85 percent; Irrigation Schedule No. 10 – 11.91 percent; Lighting Schedule No. 12 for traffic signals/15.2 – 3.98 percent; all other lighting schedules 0.00 percent. All other schedules receive an increase of between 0.57 percent and 5.85 percent. With respect to its recommended rate spread, the Division contends consideration must be given to significant issues with Company's class load data, an increasing Company cost structure and the possibility of a much needed review of the entire cost-of-service allocation methodology. The Division maintains rates should generally be cost based. However, in this proceeding it believes it is prudent to modify this position in light of the circumstances surrounding the quality of the cost-of-service analysis.

The Division recommends the rate spread be determined as follows: 1) Until issues surrounding class load responsibility can be properly addressed, no rate classes should receive a revenue reduction. Therefore, classes with an indicated revenue reduction, namely the Residential, Street & Area Lighting, Outdoor Lighting and Mobile Home Parks should remain unchanged; and 2) the remaining classes should pick up their prorated share of the overall $16.7 million revenue increase as shown in Exhibit DPU Exhibit 5-6SR. The Division also recommends that while the irrigation class' share increased notably it remains under the cost of service and any additional subsidy should be borne equally by the other classes if the Division's recommended increase is not ordered. The remaining classes should proportionately share the remaining revenue increase.

c. Office

The Office's rate spread proposal reflecting its recommended revenue requirement decrease of $11.0 million is as follows: Residential Schedule Nos. 1,2,3 – 2.0 percent decrease; Small Commercial Schedule No. 23 – 0.66 percent decrease; Large Commercial Schedule No. 6 – 0.66 percent decrease; General Service Schedule No. 8 – no change; Large Industrial Schedule No. 9 – 2.5 percent increase; and Irrigation Schedule No. 10 – 0.79 percent decrease.

The Office considered three factors in developing its rate spread recommendation. First, the Office examined the rate of return performance for each class as presented by the Company in this case to determine which classes were paying rates that closely matched their allocated costs and which classes were paying rates that were above or below the costs to serve them. Second, the Office examined the returns for individual rate schedules dating back to the Company's 2003 rate case (Docket No. 03-2035-02)[17] to determine which classes consistently produced returns reasonably close to cost of service and which classes tended to generate returns above or below cost of service. Third, the Office reviewed the Company's irrigation load data and found it to be highly inaccurate and, therefore, unsuitable for use in the Company's cost-of-service study.

[17] Docket No. 03-2035-02, "In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations."

The Office's research indicates Schedule No. 1 has been a strong performer in the Company's cost-of-service studies since 2003 and residential customers have typically been paying rates in excess of costs. In addition, Schedule No. 9 has produced relatively poor returns when compared to all major rate schedules and industrial customers have been paying rates that are substantially below costs. The deterioration in Schedule No. 9's return began in the 2006 rate case; a recent trend which has continued through to the current case. The last time Schedule No. 9's return exceeded 0.90 was in the 2004 rate case. This evidence not only supports giving Schedule No. 9 a relatively large rate increase in this case, but also underscores the need to develop a constructive rate plan for moving Schedule No. 9's return back within an acceptable range over a specified time period. In particular, the Office strongly urges the Commission to adopt a rate plan which rebalances the cost-of-service relationship between Schedules Nos. 1 and 9 within a reasonable period of time.

The Office indicated that, since determining cost of service is not an exact science, it reviewed the rates of return for the various classes in this case to determine if each class performed within a band of approximately +/- 5 percent of 1.0. Its review showed that Schedule Nos. 6 and 23 customers are paying rates that cover costs, Schedule No. 1 customers are paying rates that greatly exceed costs, Schedule No. 8 customers are paying rates that are slightly below costs and Schedule Nos. 9 and 10 customers are paying rates that are significantly below costs.

In surrebuttal, the Office indicates its continued support for the following four general principles relating to rate spread outcomes for Schedule Nos. 1, 10, 23 and 25 under different revenue requirement levels: 1) The rate increase for the Residential Schedule Nos. 1, 2 and 3 should be capped at 1.0 percent. If the revenue requirement increase in this case is below $10 million, then the Residential Schedules should not receive any rate increase; 2) at any revenue requirement increase level, Rate Schedule No. 23 (Small General Service Distribution Customers) should receive an increase at or near the jurisdictional average rate increase; 3) Schedule No. 25 (Mobile Home Parks) should receive the same level of rate increase as Schedule No. 23; and 4) at any revenue requirement increase level, Schedule No. 10 should receive the jurisdictional average rate increase.

The Office opposes the use of the Company's new load data and recommends the Commission not rely on the Company's rebuttal cost-of-service study to guide its rate spread decisions in this proceeding. The Office argues the Company cannot be allowed to propose the use of what is essentially a new cost-of-service study so late in the case, particularly when the new study has not been properly supported with evidence and has such a significant impact on a single rate class, namely an approximately $22 million cost shift from commercial and industrial customers to residential customers.

The Office argues the Company has not justified its proposal as it simply refers to the new cost-of-service study and the need to balance rate impacts among customer classes. The Company offers no evidence upon which the parties, and ultimately the Commission, can make an informed assessment that the class cost-of-service results filed by the Company in November 2009 are more accurate than the class cost-of-service results filed in June 2009.

The Office recommends the Commission order that Schedule No. 25 be eliminated over time and the remaining eleven customers be moved to Schedule No. 23. The office explains: Schedule No. 25 is a closed rate schedule involving about 11 mobile home park owners;[18] Schedule No. 25 has a rate structure similar to Schedule No. 23 (small commercial class); and mobile home park offices taking service since Schedule No. 25 was closed are served under Schedule No. 23. The Office maintains that continuation of differential pricing for mobile park owners under two separate rate schedules does not appear to be sound public policy and continuation of Schedule No. 25 results in different treatment to similarly situated customers. The Office believes it is time to take a fresh look at this issue. In rebuttal, the Company proposes to eliminate Schedule 25 in the next rate case and move the affected mobile home customers to Schedule 23 or another applicable general rate schedule.

Finally, addressing the Company's upcoming major plant additions, the Office recommends the Commission consider the upcoming major plant addition cases in making its rate spread decisions in this case. The Office believes that until any performance disparities among the customer classes are remedied in general rate cases, rate increases due to major plant addition cases occurring in between rate cases would exacerbate these differences. Therefore, the Office believes that the spread of any costs approved in major plant addition cases should be determined on a case by case basis.

d. UAE

UAE maintains that given acknowledged and demonstrated errors in the cost-of-service results in the Company's direct testimony, those results cannot reasonably be considered in the determination of rate spread. Moreover, looking back at cost-of-service results over the past several years provides no comfort because those results are based on similarly flawed data

[18] Schedule 25 has been closed for at least a decade and the same 11 mobile home park owners still take service under this rate schedule. New mobile home parks are provided service under Schedule 23 (mobile home park offices) and Schedules 1-3 (mobile home park residents).

and methodology. UAE suggests if the information produced by the Company's corrected cost-of-service methodology were to be disregarded as urged by some, then the only defensible rate spread would be an equal percentage increase to all rate classes. Further, ignoring the corrected information provided by the corrected study cannot reasonably lead to reliance on the admittedly flawed original results instead.

UAE contends even the results of the Company's corrected cost-of-service study must be viewed with caution. The peak-load disparity has not been fully reconciled and further work is needed to produce cost-of-service input data and results which can be utilized with confidence. At a time when Utah industries are struggling to climb out from the deepest recession in over 60 years -- and especially given that the industrial class is the major customer group least responsible for the load growth that is driving relentless rate increases in Utah -- UAE proposes that the most fair and reasonable approach to rate spread is either an across-the-board rate increase to all major classes or a rate spread that recognizes differential rate increases within a bandwidth of +/- 0.5 percentage points.

Under this later approach, Schedule No. 6 and Lighting classes would receive an increase that is 0.5 percentage points below the system average, Schedule Nos. 9 and 10 would receive an increase that is 0.5 percentage points above the system average and all other rate schedules would receive a uniform percentage increase approximately in the middle. As shown in Table 3, UAE provides a range of outcomes based upon the various revenue requirements recommended by the parties.

In addition to its rate spread proposal, UAE also concludes, in light of the correction presented in the Company's rebuttal cost-of-service analysis, as well as the concerns expressed in this proceeding regarding load measurement issues, an equal percentage revenue change for all rate schedules would also be reasonable.

UAE generally agrees with the direction of the Company's proposed rate spread. However, it believes it is appropriate to tighten the range of proposed increases to +/- 0.5 percent on either side of the average retail increase and to recognize a below average increase for Schedule No. 6 of 0.5 percent. UAE contends the Company's new cost-of-service study results, in combination with the class load measurement concerns raised in this case, demonstrate that the Company's cost-of-service analysis is a work in progress, underscoring the importance of using informed judgment in interpreting its results. Even though the Company's rebuttal correction removes a significant portion of the gap between jurisdictional costs allocated to Utah and the sum of class loads, the remaining unexplained gap is still of concern.

UAE remains troubled by the implications of the Company's decision several years ago to cease calibrating class loads to jurisdictional loads. These factors, in combination with the results of the Company's rebuttal correction, strongly suggests that a cautious approach should be taken in differentiating class rate increases. In UAE's view, this warrants a tighter bandwidth.

e. UIEC

In rebuttal UIEC recommends the most appropriate way to spread any increase or decrease in revenue requirements from this case is an equal percentage across-the-board adjustment to all customer classes. UIEC contends in Docket No. 08-035-38, pursuant to a settlement of parties, the Commission approved rates which under the filed rate doctrine[19] are presumed to be just and reasonable. One cannot drill through those rates and question the facts or circumstances used to make those rates. UIEC maintains those rates established rate relationships and levels, which, based on the record in this case, are the only defensible basis for rates going forward.

f. Wal-Mart

Wal-Mart did not take a position on the Company's proposed cost-of-service model, however recommended that: 1) Revenue should be allocated in accordance with the approved cost-of-service model in this docket; and 2) any rate mitigation mechanism put in place should attempt to move each customer class closer to rates based on its cost of service. Additionally, the mechanism should ensure that if a cost-based increase for a customer class falls within the banded range of percentage increases approved by the Commission, the increase for that customer class is set no higher than the cost-based increase.

Wal-Mart supports the rate spread proposal of UAE because its proposal is more consistent with the above rate mitigation principle than any other proposal. Wal-Mart believes UAE supported this basic approach at whatever overall revenue change is approved in this case.

Wal-Mart also requests that the Commission consider two additional points related to special contracts. First, the Commission should require the Company to unbundle the special contract subsidy revenues and collect those revenues on a new rate schedule separate

---

[19]Under the filed rate doctrine, "the tariffed rates 'must be charged and paid regardless of mistake, inadvertence or contrary intention of the parties.'" International Telecomms. Exch. Corp. v. MCI Telecomms. Corp., 892 F. Supp. 1520, 1541 (N.D. Ga. 1995) (quoting American Transp. Lines, Inc. v. Wrves, 985 F.2d 1065, 1067 (11th Cir. 1993))

from the existing base rate schedules. Second, the Commission should require the Company to update this new rate schedule as renewed special contracts take effect.

After reviewing the direct testimonies of the other intervener witnesses, Wal-Mart noted it had concerns that the treatment of special contract revenues would negatively impact the ability of the Company to set rates based on cost of service. Wal-Mart is concerned that three customers on “special contracts” are currently paying rates lower than their cost of service in the total amount of $16.3 million dollars and that the Company proposes to recover this shortfall only from the other customer classes, in a manner that is inconsistent with cost causation principles.

Wal-Mart proposes the Commission require the Company to unbundle the special contract subsidy revenues and collect those revenues on a new rate schedule separate from the existing base rate schedules that is then updated as renewed special contracts take effect. The benefits of this proposal include: 1) the cross-subsidy revenues collected from the Company’s customer classes for the special contracts revenue shortfall are explicitly and transparently represented in rates, meaning that price distortions are minimized, as cross subsidy revenues are no longer mixed in with base rate revenues; and 2) unbundling the shortfall revenue rates from base rates allows the Company to easily change the shortfall revenue rates as renewed special contracts take effect without having to recalculate base rates or file a full general rate case.

g. Kroger

Kroger supports the Company’s proposed rate spread. Kroger agrees with the Company that its proposed spread represents a middle-of-the-road approach that falls within an acceptable range of reasonableness when compared to the divergent recommendations presented by other parties.

Kroger recommends the Commission reject the Division's rate spread proposal as it is an extreme position given the Division argument that neither its own study nor the Company's study is reliable. Kroger proposes if the Commission finds that the load forecast data is faulty and that no cost-of-service study based on this data is reliable, as the Division has concluded, then the appropriate rate spread in this case would be a uniform percentage increase for all rate schedules. Kroger argues it does not logically follow that a party which has argued that the cost-of-service result are unreliable should support a rate spread that would move customer classes the farthest away from current rates.

h. Farm Bureau

The Farm Bureau recommends the Commission adopt the near equal rate spread proposal submitted by the Company. In the alternative, the Farm Bureau recommends the Commission should consider the plus/minus 0.5 percent rate spread proposal presented by UAE. Other rate spread proposals based only on or centered on cost of service, clearly contradict Utah Code Ann. § 54-3-1. This section, at a minimum requires the Commission to consider the economic impacts on each category of customer and the well being on the State of Utah. Moreover, the Farm Bureau argues Schedule No. 10 customers have an inconsequential impact on peak loads, the main factor that drives the cost-of-service study. Lastly, there is no serious dispute that the Company's cost-of-service study and amended cost-of-service study are each seriously flawed. Consequently, the study does not justify deviating from the Company's near equal rate spread proposal.

The Farm Bureau concludes that given the rate spread factors in Utah Code Ann. § 54-3-1 and the testimony presented in the cost-of-service/rate spread hearing, the Commission should adopt the Company's or UAE's nearly equal rate spread proposal. The rate burden placed on schedule 10 customers should not significantly be increased.

2. Discussion, Findings and Conclusions

In Table 4 we present our revenue spread decision. Consistent with most parties' positions, and based on our decisions on allocation factors, treatment of income taxes, treatment of the MSP Cap,[20] the concept of gradualism (especially in light of concerns regarding residential and irrigation load data and the forecasting of system peak load) and with consideration of the historical cost-of-service results presented by the Office, we conclude the revenue increase shall be spread to the classes as follows: the system average increase of approximately 2.2 percent shall be applied to Residential Schedules 1, 2, 3, and 25; General Service Schedules 6, 6A, 6B, 8 and 23; Electric Furnace Schedule 21; and Back-up Maintenance & Supplementary Schedule 31. No rate increase shall be allocated to Security Area Lighting Schedules 7, Street Lighting Schedules 11 and 12, and Metered Outdoor Lighting Schedule 15.1. A 1.6 times the system average increase, or approximately 3.52 percent shall be allocated to General Service Schedules 9, 9A; Irrigation Schedules 10 and 10 Time-of-Day; and Traffic Signal Systems Schedule 15.2.

These rate changes shall be implemented through a tariff rider as a line item on bills until a decision on rate design in Phase II is issued.

---

[20] The studies provided by UAE most closely reflect our decisions on the treatment of income taxes and the MSP Cap.

This spread will allow for movement toward cost of service for schedules that are and have been consistently above or below cost of service. Our decision is also consistent with our practice to refrain from giving rate decreases to specific schedules when an overall increase in revenue requirement is shown to be necessary.

Regarding Wal-Mart's recommendation pertaining to special contracts customers this issue is of concern to us as well. We direct the Company to address this issue in the next negotiation of all special contracts or in the next rate case, whichever is sooner.

TABLE 4: REVENUE SPREAD DECISION

Schedule Description	Sch. No.	Forecast Revenue	Percent Change	Dollar Change	Final Revenue
Residential:					
Residential	1, 3	$570,675,540	2.20%	$12,551,007	$583,226,547
Residential - Option TOD	2	$232,580	2.20%	$5,115	$237,695
Residential - Mobile Homes	25	$850,935	2.20%	$18,715	$869,650
AGA / Revenue Credit		$28,536			$28,536
Total Residential		$571,787,591		$12,574,837	$584,362,428
Commercial & Industrial & OSPA:					
GS - Distribution	6	$383,970,855	2.20%	$8,444,765	$392,415,620
GS - Distribution - Energy TOD	6A	$23,410,714	2.20%	$514,878	$23,925,592
GS - Distribution - Demand TOD	6B	$497,538	2.20%	$10,942	$508,480
GS - Distribution > 1,000 kW	8	$117,330,242	2.20%	$2,580,473	$119,910,715
GS - High Voltage	9	$157,303,888	3.52%	$5,535,397	$162,839,285
GS - High Voltage - Energy TOD	9A	$2,384,798	3.52%	$83,919	$2,468,717
Irrigation	10	$9,881,681	3.52%	$347,728	$10,229,409
Irrigation - TOD	10A	$1,081,109	3.52%	$38,043	$1,119,152
Electric Furnace	21	$292,021	2.20%	$6,422	$298,443
GS - Distribution - Small	23	$102,234,905	2.20%	$2,248,477	$104,483,382
Back-up, Maintenance, & Supplementary	31	$835,639	2.20%	$18,378	$854,017
Special Contracts		$84,999,118	0.00%	$0	$84,999,118
AGA / Revenue Credit		$3,445,183			$3,445,183
Total Commercial & Industrial & OSPA		$887,667,691		$19,829,423	$907,497,114
Public Street Lighting					
Security Area Lighting	7	$3,119,959	0.00%	$0	$3,119,959
Street Lighting - Company-Owned	11	$6,277,643	0.00%	$0	$6,277,643
Street Lighting - Customer Owned	12	$3,947,229	0.00%	$0	$3,947,229
Metered Outdoor Lighting	15.1	$933,273	0.00%	$0	$933,273
Traffic Signal Systems	15.2	$470,828	3.52%	$16,568	$487,396
Security Area Lighting - Contracts		$20,846	0.00%	$0	$20,846
Street Lighting - Contracts		$17,370	0.00%	$0	$17,370
AGA / Revenue Credit		$4,789			$4,789
Total Public Street Lighting		$14,791,937		$16,568	$14,808,505
Total Sales to Ultimate Customers		$1,474,247,218	2.20%	$32,420,828	$1,506,668,046

TOD = Time of Day
AGA = Annual Guarantee Adjustment
OSPA = Other Sales to Public Authorities
GS = General Service

V. ORDER

Wherefore, pursuant to our discussion, findings and conclusions made herein, we order:

1. The Company to file appropriate tariff revisions increasing Utah jurisdictional revenues by $32,414,860, effective February 18, 2010.
2. The tariff revisions shall reflect the determinations and the decisions contained in this Order. The Division shall review the tariff revisions for compliance with the terms of this Order.
3. The revenue increase will be implemented through a tariff rider on customer bills until a final order is issued in the Rate Design phase of this case.
4. Additional reports, studies, tasks and other requirements ordered herein, do not alter previous Commission requirements for filing Semi-Annual Results of Operations.

This Report and Order constitutes final agency action on the Company's June 23, 2009, Application. Pursuant to U.C.A. §63-46b-12, an aggrieved party may file, within 30 days after the date of this Report and Order, a written request for rehearing/reconsideration by the Commission. Pursuant to U.C.A. §54-7-15, failure to file such a request precludes judicial review of the Report and Order. If the Commission fails to issue an order within 20 days after the filing of such request, the request shall be considered denied. Judicial review of this Report and Order may be sought pursuant to the Utah Administrative Procedures Act (U.C.A. §63-46b-1 et seq.).

DATED at Salt Lake City, Utah, this 18th day of February, 2010.

/s/ Ted Boyer, Chairman

/s/ Ric Campbell, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#65337