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. 10-035-124** **DPU Exhibit No. 8.0D-RR** **PUBLIC**

Direct Testimony of

Brenda Salter

For the Division of Public Utilities

Department of Commerce

State of Utah

May 26, 2011

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Brenda Salter. I am employed by the Division of Public Utilities ("Division") of the Utah Department of Commerce as a Utility Analyst.

Q. What is your business address?

A. Heber M. Wells Office Building, 160 East 300 South, Salt Lake City, Utah, 84114.

Q. On whose behalf are you testifying?

A. The Division.

Q. Please describe your position and duties with the Division.

A. As a Utility Analyst, I examine public utility financial data for determination of rates and review applications for rate increases. I also research, examine, analyze, organize, document, and recommend regulatory positions on a variety of regulatory matters; review operations reports; evaluate compliance with laws and regulations; testify in hearings before the Utah Public Service Commission ("Commission"); and assist in case preparation and the analysis of testimony.

Q. Please describe your education and work experience.

A. I hold a Bachelor's degree in accounting from Brigham Young University. I began working for the Division in the spring of 2007. Since starting with the Division, I have attended the NARUC Annual Studies Program at Michigan State University. I provided testimony and appeared as a Division witness on Revenue Requirement issues in the 2007, 2008, and 2009 rate cases, Docket Nos. 07-035-93, 08-035-38, and 09-035-23, respectively. I have provided testimony and served as the managing analyst in the Major Plant Addition Docket No. 10-035-89. I was assigned to manage the rate case team and to manage and assist in the coordinating of the Division's rate case consultants. Prior to my employment with the Division, I was employed by the Utah State Tax Commission for six years as a Senior Auditor. I have testified on behalf of the Utah State Tax Commission in formal and informal hearings, and also have testified in the Third District Court as an expert witness in criminal individual income tax hearings.

Q. What is the purpose of your testimony that you are now filing?

A. My testimony introduces the Division's witnesses who testify in the revenue requirement phase of the docket, as well as Division witnesses who testified in an earlier phase of the docket and those who will still provide testimony. I will present the Division's overall revenue requirement recommendation, along with a brief explanation of the adjustments recommended by each witness.

Q. What is the Division's recommendation for revenue requirement?

A. The Division recommendation for revenue requirement is $107.4 million on a Utah-allocated basis. Beginning with the Rocky Mountain Power's (Company) filing of $232.4 million on January 24, 2011, the Division made a total of $116.41 million in adjustments with an additional adjustment to account for the Apex adjustment of $8.6 million, to arrive at a revenue requirement recommendation of $107.4 million. The Division adjustments include a $23.1 return on equity (ROE) adjustment, a total of $19.42 million in net power cost adjustments with an additional adjustment to remove a portion of the swap transactions in the amount of $24.49 million, and a total of $49.4 million in various auditing adjustments. DPU Exhibit 8.2 summarizes each of the Division adjustments. These adjustments are discussed in detail in testimony provided by separate Division witnesses.

II. BACKGROUND AND OVERVIEW

Q. Will you briefly review the background and factual framework surrounding this docket?

A. Yes. On December 1, 2010 Rocky Mountain Power filed a Notice of Intent to File General Rate Case. On January 24, 2011 the Company filed their request for a general rate case with a proposed 12-month ending June 30, 2012 forecasted test period, with its proposed electric service schedules and electric service regulations to become effective September 21, 2011. The Company's application requested an increase to its retail rates in Utah of approximately $232.4 million. On February 7, 2011, UIEC filed a motion challenging RMP's proposed test period and proposed a calendar year 2011 test period. Following a hearing on March 24, 2011, on March 30, 2011 the Commission issued its Order on Test Period approving the Company's proposed test period utilizing an average (13-month) rate base. On May 3, 2011 the Utah Rural Telecom Association filed a motion to Dismiss, Strike, or alternatively to move the pole attachment issue to a separate Docket. On May 12, 2011 the motion was heard by the Commission. As of this date the Commission has not issued its order.

III. INTRODUCTION OF WITNESSES AND ACCOMPANYING ADJUSTMENTS

Q. Please identify the Division's witnesses for the test year, rate of return, and pole attachment phases as well as the revenue requirement phase and cost of service/rate design phase of this docket.

A. DPU witness 1.0 is Dr. Joni Zenger, who filed testimony in this case on March 9, 2011. Dr. Zenger's testimony addressed the Company's proposed test year and provided the Division's position. DPU witnesses 2.0 and 3.0 are Mr. Matthew Croft and Mr. Douglas Wheelwright, who provided comparison data for the Company's actual versus forecast of plant additions and net power costs, respectively, in the test year hearing. DPU witness 4.0 is Mr. Charles Peterson, who filed testimony in this case on May 11, 2011 regarding the appropriate cost of capital for the Company. DPU witness 5.0 is Mr. Casey Coleman, who provided testimony on May 16, 2011 in the contested area of pole attachments.

Turning to the revenue requirement portion of the rate case, DPU witness 6.0 is Dr. Artie Powell, who will cover the Division's adjustments related to inter-jurisdictional allocations, the Klamath Relicensing Project, generation overhaul expense, and serve as the Division witness for policy issues. DPU witness 7.0 is Mr. Matthew Croft. Mr. Croft will address the adjustments to plant additions, depreciation rate, retirement rate, and corrections to deferred taxes. Mr. Croft also ran the Jurisdictional Allocation Model (JAM) for the Division. I am DPU witness 8.0. Along with introducing the Division's witnesses I will address adjustments to renewable energy credit (REC) revenue, non-recurring entries in FERC account 930.2, closure of the Glenrock Mine FERC account 930.2 and an adjustment to the Company's uncollectible expense. DPU witness 9.0 is Dr. Joni Zenger who will provide testimony on the Top of the World Energy, LLC power purchase agreement and an adjustment related to the sale of transmission plant. DPU witness 10.0 is Mr. Mark Garrett of the Garrett Group, LLC (Garrett Group). Mr. Garrett will present various accounting adjustments on behalf of the DPU. DPU witness 11.0 is Mr. Douglas Wheelwright. Mr. Wheelwright will present the Division's position on the Company's current hedging program. DPU witness 12.0 is Mr. George Evans of Slater Engineering, who was retained by the Division in this case for net power cost issues. Mr. Evans will discuss net power cost adjustments. Division witness 13.0 is Mr. Mark Crisp of C. H. Guernsey & Co. (Guernsey), a consultant retained by the Division who will address the gas hedging program in detail. DPU witness 14.0 is Mr. Charles Peterson, who will address the termination of negotiations for the purchase of the Apex plant. Division witness 15.0 is Mr. Richard Hahn of La Capra Associates, Inc. As a consultant, he will provide his review and recommendation regarding the Apex plant. For the cost of service/rate design portion of the rate case, DPU witness 16.0 is Dr. Abdinasir Abdulle, who will provide the Division's testimony on the allocation of the costs associated with the distribution service drops, residential minimum charge, and the Company proposed

Schedules 1 and 3 housekeeping billing changeover. DPU witness 17.0 is Lee Smith of La Capra Associates, Inc. Ms. Smith, a consultant, will provide the Division's testimony on the class cost allocations, load research, marginal cost study, and rate design.

Q. What ROE did the Division recommend for this case?

A. The Division is recommending an ROE of 10.0 percent, which, as previously mentioned, is supported by Division witness Mr. Peterson (DPU Exhibit No. 4.0). The table below sets forth the Division's recommendation regarding overall weighted average cost of capital (WACC) as discussed in Mr. Peterson's testimony (cf. beginning on page 6 in DPU Exhibit No. 4.0):

Component	Structure	Cost
Long-Term Debt	47.8%	5.81%
Preferred Stock	0.3%	5.43%
Common Stock	51.9%	10.00%
WACC	100.0%	7.98%

Q. Please explain the methodology used to model the adjustments proposed by the various Division witnesses.

A. PacifiCorp's June 2012 JAM was used in conjunction with the various "template" spreadsheets and Division work papers in order to model the adjustments proposed by the various Division witnesses. The individual templates were provided with Company witness Mr. Steven McDougal's Direct Testimony. These adjustments were then entered into the "Adjustments" tab in the JAM. The following exhibits correspond to these templates:

DPU Exhibit 8.1 – DPU JAM

DPU Exhibit 8.2 – DPU Revenue Requirement Spreadsheet

DPU Exhibit 8.7 – DPU Wage Adjustment Inputs for JAM

Q. Did you prepare a summary of the Division's adjustments that you describe above?

A. Yes. Attached to my testimony is DPU Exhibit 8.2, which summarizes each of the Division's adjustments. This spreadsheet originated from the "Adjustment Summary" tab in DPU Exhibit 8.1 (DPU JAM). In general, all of the adjustments in DPU Exhibit 8.2 may differ slightly from what is included in other Division exhibits due to the effect of the MSP cap, taxes, and how the JAM is run.

Q. Please describe the methodology that you used in entering the inputs into the JAM.

A. Each of the accounting adjustments was entered into the model in the order listed in DPU Exhibit 8.2. For instance, the first adjustment entered into the JAM was Division Witness Mr. Peterson's adjustment to the Company's cost of capital and the last adjustment entered was Division Witness Dr. Powell's rolled in/revised protocol adjustment.

Q. What adjustments do you propose?

A. My testimony addresses adjustments made by Company witness Mr. Steven McDougal to renewable energy credit (REC) revenue 3.4, my review and adjustment to the Company's proposed uncollectible expense 4.17, as well as my review and adjustment to Miscellaneous General Expense Federal Energy Regulatory Commission ("FERC") Account 930.2. In addition to reviewing the above, I also reviewed Mr. McDougal's adjustments to SO_2 Emissions Allowance 3.4, DSM Expense and Revenue Removal 4.5, Irrigation Load Control Program 4.2, and Customer Service Deposits Exhibit 8.6.

Q. Please provide an overview of your adjustments.

A. I propose an increase in total company revenue based on a change to Mr. McDougal's REC Revenue adjustment in the amount of $30,433,195. Utah's allocated adjustment results in a $17,984,770 increase in revenue. I propose an adjustment to FERC account 904, uncollectible accounts that results in a Utah uncollectible expense adjustment of $367,286. My final adjustment applies to FERC account 930.2, Miscellaneous General Expense and results in a decrease in the amount of $637,310 total company and Utah since the adjusted amount is situs assigned. This adjustment relates to two separate issues in FERC 930.2, Challenge Grants and the Glenrock Mine closure.

IV. ADJUSTMENTS

RENEWABLE ENERGY CREDIT REVENUE

Q. Please describe your adjustment to REC revenue.

A. My adjustment to REC revenue stems from Mr. McDougal's adjustment 3.4, REC revenue. I propose an adjustment to the estimated price of wind credits available for sale and vintage RECs presented in Mr. McDougal's Testimony RMP__(SRM-3) page 3.4.2. RECs are tradable environmental commodities that represent proof that energy was generated from an eligible renewable source. RECs can be sold separately from the energy generated or they can be retained to meet renewable portfolio standards (RPS), which the Company is currently obligated to meet in Oregon, California and Washington.

Q. What is the Company's proposed REC revenue adjustment for the June 2012 period?

A. After the Company makes the adjustment to remove the REC amounts reserved for Oregon, California and Washington RPS requirements the Company then makes an adjustment to hold 25% of the remaining RECs as a buffer to intermittent wind capacity. The Company then proposes a three stage approach to the sale of the remaining RECs. The first stage is the sale of contracted REC sales otherwise referred to as "Known Sales" on RMP__(SRM-3) page 3.4.2. Known Sales are the Company's contracts that were known at the time of filing the case. The Company has not included REC contract sales in previous rate case filings. The second stage is the sale of "available wind credits remaining for sale." Company witness Mr. Stefan Bird states the only visible forward market for the Company to rely on for the forward purchase is the broker market. According to Mr. Bird, the current price for an unbundled REC is approximately $7.00[1]. The third stage is the sale of "Vintage RECs," or the sale of RECs remaining prior to the test year. Accord to Mr. Bird the Vintage RECs average between $2.00 and $4.00 and are priced at $4.00 for this case[2]. The Company's adjustment decreased the REC revenue by $42.8 million in the test period. The Company justifies this decrease based on the lack of negotiated contracts at prices that cannot be achieved through the broker market.

Q. Mr. Bird indicated that the Company had issued a Short-Term RFP for renewable energy resources on November 4, 2010. Please provide an update to this bid.

A. In response to Mr. Bird's testimony, the Division issued DPU DR 10.52 requesting the Company provide the updated REC revenue RFP information. On March 17, 2011 the Company provided an updated REC revenue adjustment page similar to Mr. McDougal's Exhibit 3.4 which included the NV Energy contract amounts since the contract had been awarded to the Company. The Company subsequently provided a Supplemental adjustment to DPU DR 10.52 on March 28, 2011 with additional changes. The Company's supplemental response changes the Company's original REC revenue adjustment of $42.8 million to a revised REC revenue adjustment of $12.4 million.

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[1] Direct Testimony of Stefan A. Bird p. 4-5, lines 90-94.
[2] Direct Testimony of Stefan A. Bird p. 5, lines 94-97.

Q. Do you agree with the REC sales price as proposed by the Company?

A. I have reviewed the Company's REC sales contracts and believe the Company has fairly represented the known wind and known non-wind sales for the test period as presented in DPU DR 10.52 - 2 1st Supplemental. What I cannot agree with is the Company's estimated sales price for non-contract REC sales, whether it is for the available wind credits remaining for sale of $7.00 or the Vintage RECs of $4.00. The Company has shown in the past that its estimated sales price is not in line with what has actually been sold. For example the Company estimated its 12 months ending December 2009 REC revenue in the 2008 general rate case to be $6.1 million[3], when the actual 12 month period resulted in REC sales of $50.8 million[4]. The following year the Company filed its 2009 general rate case with estimated REC revenue sales for the period ending June 2010 at $6.4 million[5]. The Company's Utah jurisdiction results of operations for the same period indicates REC revenues booked of $98.5 million[6]. It is interesting that in this case the Company has asked for a decrease in REC revenue when the Company's forecasts have previously been grossly understated.

Q. Please explain your adjustment to REC revenue.

A. My recommended adjustment to REC revenue is comprised of two parts. First, I include the Company's response to DPU DR 10.52 -2 1st Supplemental, since the Company

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[3] Rocky Mountain Power General Rate Case Second Supplemental Exhibit RMP__SRM-2SS testimony of Steven McDougal pg 3.4.2.
[4] Rocky Mountain Power Utah Jurisdiction Results of Operations for the Period Ending December 2009 pg 3.5.2.
[5] Rocky Mountain Power General Rate Case Exhibit RMP__SRM-2 testimony of Steven McDougal pg 3.5.2.
[6] Rocky Mountain Power Utah Jurisdiction Results of Operations for the Period Ending June 2010 pg 3.5.1.

provided the corrected contract information but has not at this time incorporated the changes into the case. Second, the Division is recommending a REC Tracker be established in order to help alleviate the fluctuation the Company is seeing in its market REC price. The Company and other parties have expressed concerns with the REC market instability. A REC revenue tracker will help to alleviate this instability. To simplify the process, the tracker could be structured in a way that filings and rate adjustments would follow the Company's recently implemented energy balancing account (EBA). This would enable the REC revenues to be trued up at the same time as the EBA expenses. The Division believes the best approach would be to have the two programs run parallel to each other but reported in separate dockets. The Division requests to have the tracker implemented on a temporary basis until the market has had a chance to stabilize.

Q. What is the effect of your adjustment to REC revenue?

A. My adjustment (DPU Exhibit 8.3) to the REC Revenue increases revenues by $30,433,195 (total company) or $17,984,770 (Utah's allocated share) for the test period.

Q. If the Commission chooses not to adopt a REC Tracker what is your recommendation regarding the value of the available wind credits remaining for sale and the Vintage RECs?

A. If the Commission does not adopt a REC Tracker, I believe it is more appropriate to use actual data rather than forecasted data that has proved to be grossly wrong in the past.

Confidential Attachment UAE DR 5.3 provided by the Company stated the average REC sales price the Company received for 2010 wind-related RECs was [redacted] per MWh. This is a better representation of what the Company would expect REC sales to be in the test year and is what the Division is recommending be used, if the tracker is not adopted, as the value of the available wind credits remaining for sale and the Vintage RECS.

Q. Is there support showing the average sale price of RECs is increasing?

A. The Company estimated the average REC price it would receive for the 2011 and 2012 years would be $[redacted] per MWh and [redacted] per MWh respectively[7]. Although these prices do not show a steady increase, they do indicate the Company expects a higher average REC price in the 2012 test year.

Q. If the Commission does not approve a REC Tracker, what would be your proposed adjustment to REC revenue?

A. My adjustment to the REC Revenue without a Tracker would increase revenues by $70,635,726 (total company) or $30,574,046 (Utah's allocated share) for the test period. This amount includes the recommended adjustment of $17,984,770 as well as the amount reflecting higher expected REC prices.

UNCOLLECTIBLE ACCOUNTS EXPENSE - FERC ACCOUNT 904

[7] Confidential Attachment UAE DR 5.4.

Q. Has the Company included an adjustment to the uncollectible expense in this rate case?

A. Yes, the Company calculated an uncollectible expense rate of 0.315% by dividing Utah's June 2010 unadjusted uncollectible expense (FERC 904) by Utah's June 2010 unadjusted general business revenue. This uncollectible expense rate of 0.315% was then applied to the Company's proposed Utah June 2012 normalized general business revenue resulting in an approximate $5.4 million uncollectible expense.

Q. Do you agree with the Company's proposed uncollectible expense included in the case?

A. No. I believe the proposed level is too high.

Q. What level of uncollectible expense do you propose be included in the case?

A. I recommend that a rate of 0.290 % be set as the uncollectible expense rate for this case. Table 8.1 below compares a rolling 12 month average uncollectible rate[8], beginning with the 12 months ended December 2006 and continuing through the most current date available to the Division of March 2011[9].

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[8] Uncollectible Rate = Utah FERC 904 Expense/Utah General Business Revenue.
[9] Uncollectible Rate = Retail Bad Debt Expense/Retail Sales Revenue from RMP's response to DPU DR 18.4.

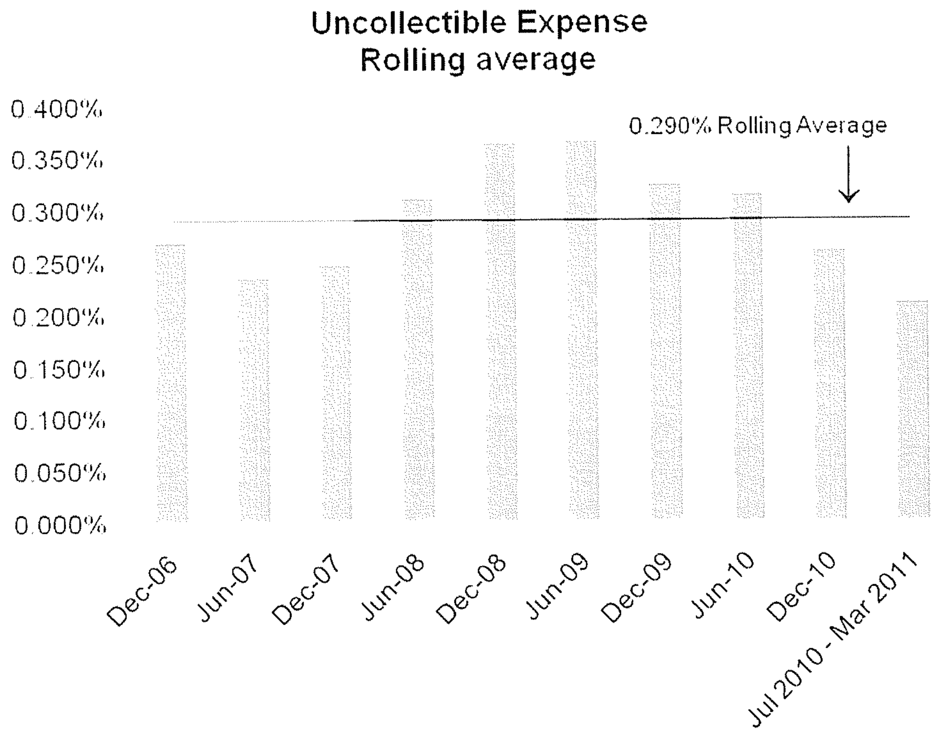

Table 8.1

As can be seen from Table 8.1 the Company's requested 0.315% uncollectible expense rate is markedly higher than what the Company is currently experiencing. This is an indication that an even lower uncollectible rate could be implemented than the Division's requested 0.290%.

The Division asked the Company to provide any strategies the Company has implemented to reduce its uncollectible expense. The Company's response indicated that a plan was initiated in 2009 and was later modified in 2010 and 2011. The plan covers four areas: increase effort to help customers reduce and manage their bills, increase effort to help customers obtain financial assistance, obtain deposits from at-risk customers, and utilize targeted field collections. The plan has been successful in managing the uncollectible debt of the Company[10]. Table 8.1 indicates the Company's uncollectible expense plan is working.

Q. Is it your understanding that uncollectible expense follows revenue?

A. No, this is not necessarily true. Efforts can be taken to reduce the uncollectible expense a company experiences. Listed in Table 8.2 are the historic levels of uncollectible expense and revenues recorded by the Company for calendar years 2006 through 2010.

TABLE 8.2

Uncollectible Expense By Year

Year	Amount	Revenues	Percent
2006	$3,246,950	$1,208,074,346	0.269%
2007	$3,423,982	$1,387,524,553	0.247%
2008	$5,164,020	$1,421,492,765	0.363%
2009	$4,711,943	$1,452,430,658	0.324%
2010	$4,011,727	$1,542,874,059	0.260%

Mr. McDougal stated in his testimony that the Company's requested uncollectible expense be increased to account for the additional revenue it anticipates in the 12 months ended June 30, 2012[11]. As shown above the level of revenue does not always dictate the level of uncollectible expense.

Q. What is your proposed level of Utah uncollectible expense for the Test Year?

[10] The Company's response to DPU DR 18.5.
[11] Mr. McDougal's Direct Testimony Pg 34, lines 769 through 770.

A. The Division is proposing to normalize the uncollectible expense by taking a rolling average of the actual Utah uncollectible expense as a percentage of Utah general business revenues. This results in a Utah uncollectible expense of 0.290%. Applying this percentage to the Division's proposed June 2012 general business revenues gives an uncollectible expense for the Test Year of $4,988,885. The Division believes this amount is more in line with expectations of the conditions expected during the Company's proposed Test Year.

Q. How does your proposed adjustment to uncollectible expense differ from your 2009 general rate case adjustment?

A. My adjustment in this case takes into account five years of uncollectible expense data while my adjustment in 2009 incorporated only three years of data.

Q. What persuaded you to include additional years in your evaluation?

A. Using a rolling average of five years helps to create a smoothing effect on data that are hard to predict or vary significantly from year to year. A case in point is the economic recession over the last few years. My Table 8.1 clearly indicates when the recession began. The 12 months ending December 2008 uncollectible expense and the 12 months ending June 2009 appear to be anomalous periods. In order to get a better picture of what a normal uncollectible expense would be one could remove the anomalous periods from a 3-year average and include periods prior to the recession, or smooth the five years with a rolling average. Rather than removing data, the better fit was to use a rolling average.

Q. How does your adjustment differ from the Company's adjustment in this case and the 2009 case?

A. The Company's uncollectible expense has proven to be volatile with swings in both directions. My adjustment has incorporated a smoothing mechanism that has the ability to remove some of the volatility. The Company's adjustment in the 2009 rate case used the uncollectible expense in the base year and escalated it. In this case the Company chose to use the base year uncollectible expense rate as explained in Mr. McDougal's Exhibit RMP__SRM-2 page 32 and 33. Neither of the Company's methods took into account the volatility of the uncollectible expense.

GLENROCK COAL MINE – FERC ACCOUNT 930

Q. Please explain your adjustment to FERC Account 930.2 Miscellaneous General Expense.

A. In 1997 the Company made the decision to close the Glenrock coal mine due to a negotiated rail transportation contract that would make purchasing market coal more economic than continuing to operate the Glenrock mine. The Company began amortization of the reclamation costs in 1998 and the unrecovered plant in 1999 as approved in Docket Nos. 99-035-10 and 01-035-01. The reclamation costs were fully amortized in 2002.

During the base year, the Company made journal entries to FERC Account 930 Miscellaneous General Expense amortizing unrecovered plant of the Glenrock coal mine closure. The Company's response to DPU DR 10.49 states the regulatory asset was fully amortized in September 2010. The above adjustment removes non-recurring expenses as a result of the Glenrock coal mine closure in the amount of $437,888 from base year expenses.

CHALLENGE GRANTS

Q. Please explain your Challenge Grant adjustment to FERC account 930.2.

A. The Division removes 100 percent of the Challenge Grant expense, since it appears these expenses are related to civic activities, which regulated utilities are not allowed to recover from ratepayers. Civic activities are discretionary and are not required to provide safe and adequate service to customers. The Commission has not allowed regulated utilities to recover contributions for charities and community affairs through rates charged for regulated services. This adjustment reduces revenue requirement by $199,422.

V. CONCLUSION

Q. In conclusion, please restate the Division's recommendation for revenue requirement.

A. The Division recommendation for revenue requirement is $107.4 million. The Division made a total of $125.01 million in adjustments. The Division adjustments were a $23.1 ROE adjustment, a total of $43.91 million in net power cost adjustments, and a total of $58.0 million in various auditing adjustments.

Q. Does this complete your testimony?

A. Yes it does.