-BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH-

In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Rate Schedules & Electric Service Regulations	|	**DOCKET NO. 06-035-21** Utah Division of Public Utilities Exhibit DPU No. 2.0

STIPULATION TESTIMONY

OF

THOMAS BRILL, PH.D.

FOR THE

DIVISION OF PUBLIC UTILITIES

DEPARTMENT OF COMMERCE

STATE OF UTAH

August 17, 2006

STIPULATION TESTIMONY OF DR. THOMAS C. BRILL

TABLE OF CONTENTS

		Page
I.	INTRODUCTION	1
II.	BACKGROUND AND SUMMARY	3
III.	EXPLANATION OF THE TEST YEAR	6
IV.	THE DIVISION'S ANALYSIS AND FINDINGS	10
	A. LOAD FORECASTING	15
	B. AUDITING ADJUSTMENTS	20
	C. RETURN ON EQUITY	27
	D. NET POWER COSTS	31
	E. RATE SPREAD	33
V.	SUMMARY OF DIVISION ADJUSTMENTS FOR SETTLEMENT PURPOSES	38
VI.	CONCLUSION	41
VII.	EXHIBITS	
	2.1 RESUME OF DR. THOMAS C. BRILL	
	2.2 JULY 21, 2006, LETTER FROM ROCKY MOUNTAIN POWER (MEMORIALIZATION OF COMMITMENTS)	
	2.3 DIVISION ADJUSTMENTS FOR HIGH END SETTLEMENT PURPOSES	
	2.4 DIVISION ADJUSTMENTS FOR LOW END SETTLEMENT PURPOSES	

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME

A. Dr. Thomas C. Brill.

Q. WHAT IS YOUR BUSINESS ADDRESS?

A. My business address is 160 East 300 South, Heber M. Wells Building, Salt Lake City, Utah, 84114.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am employed by the Division of Public Utilities ("Division" or "DPU") of the Department of Commerce as a Technical Consultant in the Energy Section.

Q. PLEASE DESCRIBE YOUR EDUCATION & PROFESSIONAL EXPERIENCE.

A. I attended the University of New Mexico and earned an M.A. in Economics in 1989 and a Ph.D. in Economics in 1993. From 1981 to 1988 I worked as an oil and gas industry analyst with the Energy Information Administration. I also worked at the New Mexico State Land Office and at the New Mexico Water Resources Research Institute. I later served as an oil and gas analyst with the Utah Office of Energy and Resource Planning. For the three years prior to coming to the Division, I served as the Director of the Utah Energy Office, with a primary responsibility of responding to a financial audit. My resume is attached as DPU Exhibit No. 2.1.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?**

A. No. This is the first time I have testified before the Utah Public Service Commission ("Commission"). However, I have testified in this type of regulatory forum in the past before various legislative committees as an analyst and as Director for the Utah Energy Office. Topics covered were jet fuel market analysis, overall petroleum product supply and demand, natural gas market analysis, the Utah energy situation, and annual budget appropriations.

Q. PLEASE OUTLINE THE PROJECTS YOU HAVE WORKED ON SINCE COMING TO THE DIVISION.

A. I joined the Division in June 2005 and participated in several of the ongoing task forces. I worked on the Division's assessment of coal and natural gas resources and the role these fuels play in electric generation. Since December 2005 I managed the Division's team that investigated the Purchase Cost Adjustment Mechanism ("PCAM") application. Since February 2006, I managed the Division's team that investigated PacifiCorp's (the "Company") general rate case application. PacifiCorp has now changed its name to Rocky Mountain Power.

Q. PLEASE DESCRIBE YOUR ROLE IN THE DIVISION'S INVESTIGATION AND FINDINGS PERTAINING TO THIS GENERAL RATE CASE.

A. From the initial stages of the case, I planned the entire team assignments and performed the role of manager of the rate case for the Division. I served as the liaison with the Company and was instrumental in making sure that all data requests were properly answered and coded correctly. In addition, I scheduled all meetings, both internally within the Division and with other parties. As the investigation progressed, I was actively involved in all stages of the audit and analysis. I met weekly and sometimes daily with other Division employees to study and examine findings. I participated in all settlement conferences and met mutually with Division staff to justify each finding and the Division's position on all matters pertaining to the case.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. The purpose of my testimony is to present the Division's analysis and findings in this docket and to explain how we arrived at our position in support of the settlement stipulation.

II. BACKGROUND AND SUMMARY

Q. WILL YOU PLEASE BRIEFLY REVIEW THE BACKGROUND AND FACTUAL FRAMEWORK SURROUNDING THIS DOCKET?

A. Yes. On March 7, 2006, PacifiCorp filed an application with the Commission for a general rate increase of $197.2 million, based on a 12-month forecasted test period ending

September 30, 2007. This increase included a request for a ROE of 11.4 percent. On April 5, 2006, the Company filed supplemental testimony, reducing the rate increase to $194 million in a forecast adjustment.

The Division reviewed the filing, the Master Data Request, and evidence presented by PacifiCorp, the Division, the Committee of Consumer Services, the Utah Industrial Energy Consumers, the UAE Intervention Group, AARP, the Federal Executive Agencies, and Nucor Steel (the “Parties”). The Division participated in settlement conferences with the Parties on July 10, 11, and 12, 2006. The Division also met with PacifiCorp and studied documents in the reading room in order to identify and clarify issues of concern. As described below, our auditors traveled to Portland in April and May to examine documents and ask further questions. In addition, the Division sent out and reviewed 16 sets of data requests to the Company, totaling approximately 253 questions pertaining to the filing. Our auditors and investigative teams were able to complete a sufficient audit that allowed us to arrive at an agreement and form a Stipulation. As a result of our findings and the work that the Parties performed in the settlement negotiations, most of the Parties arrived at a Stipulation that was filed on July 21, 2006.

As I will describe below in the following sections, the Division was able to make prudent and firm adjustments where needed and come to a consensus with the Parties on the revenue requirement, rate spread, and other matters specified in the Stipulation. I will also describe matters that were left unresolved or kept out of the Stipulation.

Q. WHAT SETTLEMENT WAS REACHED ON THE UTAH RATE INCREASE?

A. The settlement that was reached, as described in the Stipulation, allows the Company to increase its revenues by $115 million over rates currently in effect. The increase will be implemented in two phases: $85 million, effective December 11, 2006; and an additional $30 million on June 1, 2007. There is no overall agreement as to the test period or revenue requirement adjustments (except return on common equity) that led to the stipulated revenue requirement increases due to the fact that the Parties relied on different test periods and adjustments in supporting the agreed upon $115 million increase.

Other aspects that were stipulated to include the following: an annualized rate credit of $30 million to customers beginning on December 11, 2006, and terminating on June 1, 2007 due to the Commercial Operation Date of the Lakeside Generating Unit; the return on common equity of 10.25 percent; all rate increase revenues will be allocated to tariff customer classes and not to special contract customers; the Utah County IM Flash Technologies' projected load should be included in the retail load forecast; PacifiCorp will not file another Utah general rate increase or another PCAM before December 11, 2007; and finally that PacifiCorp will withdraw the PCAM application in Docket No. 05-

035-102. The complete settlement is listed in its entirety in the Stipulation dated July 21, 2006 and filed on July 26, 2006.

Q. WHAT GUIDED THE DIVISION'S OVERALL ANALYSIS IN THIS CASE?

A. The Division's investigation and analysis were based on the premise that the terms and conditions, both individually and considered together as a whole, must produce just and reasonable results that are in the public interest. The Division's mission statement accurately reflects our analysis and investigation used in this case and all of our work:

> The Division of Public Utilities promotes the public interest in utility regulation and works to assure that all utility customers have access to safe, reliable service at reasonable prices.

By statute, the Division is charged with balancing the interests of the regulated utilities and their ratepayers. This means we work to ensure that utility rates and tariffs are just and reasonable and that the utility (or the Company in this case) should be granted the opportunity to have its revenues cover its costs.

IV. EXPLANATION OF THE TEST YEAR

Q. REGARDING THE ISSUE OF WHICH TEST YEAR TO USE IN THE ANALYSIS, WILL YOU PROVIDE A BRIEF BACKGROUND OF EVENTS THAT HAVE TAKEN PLACE WITH RESPECT TO THIS DOCKET?

A. To begin with, as a result of the last PacifiCorp general rate case that was stipulated to, a Test Period Task Force was formed. The result of the task force work group was an agreement regarding what specific items PacifiCorp would file in the next case. There was also a tentative agreement that the test period that was used in the next case (meaning this docket) would be established within the first 65 days of the 240-day general rate case calendar, and it would be agreed upon either by stipulation of all parties or through a Commission Order. Division witness Dr. George Compton analyzed the test-period issue at great length, and the Division's position is that a future test year is appropriate, in this docket, with mitigating measures in place.

Q. THE CURRENT UTAH TEST YEAR STATUTE IS CITED AT UTAH CODE ANN. § 54-4-4. WHAT DOES THE TEST-YEAR STATUTE STATE?

A. The statute identifies three possible test periods: (1) fully forecasted, (2) fully historical with known and measurable adjustments, and (3) a combination of a historical and forecasted test period.

Q. WHICH OF THOSE ALTERNATIVES WAS CHOSEN BY THE DIVISION, AND ON WHAT BASIS?

A. The Direct Testimony filed on June 9, 2006, by Dr. George Compton on this subject, concluded that the fully forecasted, future test period ending September 30, 2007, was the most defensible. The Division's support for this test period was based on a recognized need for PacifiCorp to recover the costs of large plant additions that would be taking place during, or just preceding, the rate effective period. The alternative test periods would not have satisfactorily accomplished that objective either because some investment would be left out entirely, others would only be entered into the rate base partially, and, generally, there would be a mismatch among loads, operating expenses, and plant in service.

Confidence regarding our choice of test period was enhanced by virtue of the Stipulation bringing in a number of elements that reduced or eliminated uncertainties regarding the accuracy of future cost projections within a test-year context. One such element was to truncate the period over which general inflationary pressures would be brought to bear. More notably, the proposed rate increase was bifurcated so as to delay a major portion thereof until the new large Lakeside generation plant was actually operational. That eliminated the possibility of collecting revenues for a plant whose completion date is unknown.

Q. WERE THERE OTHER STEPS THAT WERE STIPULATED TO AS PART OF THE AGREEMENT IN ORDER TO LIMIT THE HAZARDS OF OVER-FORECASTING FUTURE COSTS AND TO DEAL WITH THE UNCERTAINTIES THAT COME WITH A FUTURE TEST PERIOD?

A. Yes. The Company issued a letter to the Division and the Committee of Consumer Services dated July 21, 2006. This side letter memorialized the commitments and promises that were agreed to in the Stipulation, also dated July 21, 2006. The letter, which also reflects the Company's name change to Rocky Mountain Power, is attached to my testimony as Exhibit No. 2.2. With these mitigating measures in place, the Division can support the fully forecasted test period ending on September 30, 2007. The items listed in Rocky Mountain Power's July 21 letter are listed below:

1. Forecasted Results of Operations. During the period from October 2006, to September 2007, PacifiCorp's expenditures for distribution maintenance set forth in FERC accounts 590 through 598 will be not be less than 90 percent of $67.5 million. During the period from October 2006, to September 2007, PacifiCorp's capital costs for pole replacement expenditures will be not less than $5.1 million.

2. Variance Report. PacifiCorp further agrees that it will provide information on certain items that may vary from the information in the forecasted revenue requirement in Docket No. 06-035-21. The Company will include a new tab in its Results of Operations Report filed on September 30, 2007, for the period ending June 30, 2007, on a one-time basis that will include the following factual information:

   - MEHC corporate charges incurred,

- Demand and energy loads,
- Manpower levels and associated benefit costs, and
- Capital additions

3. PacifiCorp agrees that it will withdraw its PCAM application in Docket No. 05-035-102. PacifiCorp also agrees that its next application for a PCAM will be filed no earlier than December 11, 2007.

III. THE DIVISION'S ANALYSIS AND FINDINGS

Q. BEFORE WE GET TO THE SPECIFIC ADJUSTMENTS THAT LED TO THE SETTLEMENT STIPULATION, WILL YOU EXPLAIN THE WORK THAT THE DIVISION UNDERTOOK IN CONNECTION WITH THE INITIAL FILING OF THE GENERAL RATE CASE?

A. First, it is important to note that the Division's audit was facilitated and expedited in this case, due to the advanced notice of the rate case filing, the base test year, and the awareness of the major drivers contributing to the proposed rate increase. This knowledge enabled the Division to begin our review in advance of the Company's filing, including defining the audit scope, identifying specific issues, and preparing an initial set of data requests. We also had knowledge gained through our recent review of due diligence in conjunction with the MidAmerican acquisition of PacifiCorp's future obligations. In addition, at the time of the filing, the Company provided responses to the Master Data Request as agreed to by the Discovery Task Force.

I should also note, that unlike previous audits, the Division had access to the Company's accounting system, SAP, and therefore was able to perform queries and account downloads on a real-time basis, rather than having to go through the data request procedure to obtain this data.

Q. IT APPEARS THAT THE TASK FORCE WORK WAS BENEFICIAL IN THAT IT ALLOWED THE DIVISION AUDITORS TO GET A JUMP START ON THE WORK. SPECIFICALLY, WILL YOU DESCRIBE THE METHODOLOGY AND THE GENERAL AUDIT PROCEDURES THAT WERE USED BY THE DIVISION?

A. Yes. As part of our audit, the Division had five auditors travel to Portland for the week of April 3-7, 2006. Then again, our auditors went to Portland for almost a week in mid-May. As part of the process there were five preliminary settlement conferences that took place in late April and early May. A framework for the settlement proposal was agreed to in early May. This explains the background of part of the audit work.

Then, the first step in our audit procedure was to ensure that the base year had been properly adjusted to remove expenditures not allowed in rates, extraordinary and out of period items, and non-recurring items. As the base year, 12 months ending September 2005, encompassed two Fiscal Years, the later six months of FY05 and the first six months of FY06, we expanded our audit scope with respect to monthly accruals, to ensure the base year did not include more than 12 monthly accruals for any item.

Q. THE MIDAMERICAN ACQUISITION OF PACIFICORP WAS FINALIZED AFTER THE GENERAL RATE CASE HAD BEEN FILED. DID THIS THROW A WRENCH INTO YOUR WORK?

A. Not entirely, but the Division did take on additional steps in auditing as a result of the acquisition. First, we determined that all transaction costs had been appropriately accounted for below-the-line and not included in regulated operations. Second, we determined that all charges included in the base year as a result of ScottishPower's previous ownership had been removed. We verified that, in fact, the Company had set up a work order to which all transaction costs were to be charged. We next obtained and reviewed executives' expense reports to verify that all activity related to the MidAmerican transaction had been appropriately charged to the work order. Our review resulted in no exceptions.

Q. DID YOU TAKE ANY OTHER MEASURES TO LOOK AT MIDAMERICAN CORPORATE CHARGES OR ALLOCATIONS TO PACIFICORP?

A. Yes, the acquisition led us to look at several other areas of concern after the Company's subsequent filing. First, Division auditors determined that outside services constituted a significant portion of the Company's operating expense. Therefore, we performed a detailed analysis of the outside services account for the purpose of identifying services performed in the base year that would not be ongoing in the future, or that had a high probability of being performed in-house subsequent to the MidAmerican acquisition.

The Division also found that, subsequent to the MidAmerican acquisition, property and liability insurance provided by ScottishPower's captive insurance company ceased. Additionally, the Company's other insurance policies terminated either on March 31, 2006, or on the acquisition date. The Division's auditors met with MidAmerican to discuss its newly established captive insurance company and coverage provided. We also obtained the current term sheets for all other policies. In addition, we reviewed the Company's property and liability insurance reserves for reasonableness.

Next, the Division obtained MidAmerican's budget that supported MidAmerican's charges to PacifiCorp that were included in the filing update. In addition, we obtained MidAmerican's corporate budget from prior years and tested for reasonableness. We verified that all budgeted items not appropriate for rate recovery had been removed and that the $9 million cap was not exceeded. It should be noted that MidAmerican's corporate charges included in this case represent the budget for calendar year 2006 and have not been adjusted for projected wage increases or cost increases beyond that date.

Q. NOW, BACK TO THE REST OF THE AUDIT. WILL YOU PLEASE DISCUSS THE LOGIC BEHIND EACH OF THE DIVISION'S ADJUSTMENTS?

A. Yes, the Division's next step was to determine the reasonableness of the Company's proposed adjustments and projections to the test year. We independently verified each adjustment in the Company's filing, including tracing the adjustment's calculation to the Company's books and records, invoices, billings, budgets, work orders, contracts, etc., as required.

Q. WHAT AREAS DID THE DIVISION DETERMINE DEEMED FURTHER ANALYSIS AT THIS POINT?

A. The Division selected several areas for further detailed analysis, based on the overall effect that the areas could have on the Company's revenue requirement and the assessed potential for future changes and/or adjustments not reflected in the Company's filing. The topics listed below are areas in which the Division directed further detailed analysis:

- Company's Load Forecast
- Major Plant Additions
- Maintenance, Transmission and Distribution Expenditures
- Power Costs

- Outside Services
- Insurance
- MidAmerican Corporate Charges/Allocations to PacifiCorp
- Salaries & Wages, Employee Benefits, Pensions
- Inflation Factors

In addition to the above, our audit procedures included the accounts during the base year, as well as prior to, and subsequent to, the test year; a review of Board Minutes, internal audit reports and outside auditor's work papers; as well as interviews with Company personnel responsible for transmission and distribution budgets, insurance, personnel matters, and gas procurement activities. We also updated adjustments for known and measurable changes that took place during the course of our review.

Q. WILL YOU PLEASE EXPLAIN THE ADDITIONAL DETAILED WORK THAT THE DIVISION PERFORMED IN EACH OF THESE SPECIFIC AREAS?

A. Yes, I previously mentioned our review of some of the above-mentioned items, but I will explain in detail each of the other main components.

A. LOAD FORECASTING

Q. OKAY, LET'S FIRST START WITH LOAD GROWTH. HOW IS LOAD FORECASTING CALCULATED AND WHAT ADJUSTMENTS WERE MADE CONCERNING LOAD GROWTH AND LOAD FORECASTING?

A. The Company's load forecast drives power costs as well as the overall allocation of total Company expenses to the Utah jurisdiction. Therefore, the Division performed our own independent load forecast led by Dr. Abdinasir Abdulle. As found in the testimony of PacifiCorp witness, Mark Klein, and subsequent Company responses to Division data requests and informal communications, the Company developed, using the same methodology the Company used in prior cases, forecasts of the number of customers, kWh sales, system loads, system peaks, and rate schedule for the 12-month periods ending September 2006 and September 2007. These forecasted values were used to calculate present revenues for the forecasted test period, to assist in the development of the distribution costs, to estimate load resource balances in the net power cost study, and to calculate inter-jurisdictional allocation factors used in the revenue requirement and cost of service study.

Q. HOW ARE THE ANNUAL SALES FORECASTED FOR THE DIFFERENT CLASSES OF CUSTOMERS?

A. In developing the sales forecasts for the Residential, Public Streets and Highway Lighting, and Irrigation classes, the Company developed forecasts for the number of customers (using weighted exponential smoothing) and the energy use per customer (using both time-series and regression analysis) for each class. The annual sales forecast for these classes is the product of these two forecasts. The Company reviews these forecasts for reasonableness and has made adjustments when needed in the past.

Q. ARE THE SALES FORECASTS FOR THE INDUSTRIAL CUSTOMERS CALCULATED THE SAME WAY?

A. Not necessarily. Because industrial customers are heterogeneous in size and energy usage, the energy sales forecast for the Industrial and Other Sales to Public Authorities relied heavily on consultations with the account managers assigned to each large power user and reviews of industry trends to develop energy sales forecast for each Standard Industrial Classification (SIC). The annual sales forecast for the industrial class is the sum of the forecasts for these SIC groups.

Q. HOW WERE THE MONTHLY FORECASTS FOR THIS GENERAL RATE CASE DEVELOPED?

A. To develop the monthly forecasts, annual system load forecasts were calculated by adding line losses to the annual forecasts. The annual system load values are then distributed to hourly values using a regression model of hourly loads against a combination of temperature data, spatial dummy variables, a moving average of 8,760 hourly periods, and crossed binary variables. These hourly values are then aggregated to monthly totals. Line losses are then subtracted to establish total state values at sales level. Finally, an average monthly load shape is developed for each state and customer class. This shape was then applied to the annual forecasts for each state and to each customer class to arrive at monthly values. The Division generally agrees with this procedure.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S SALES FORECASTS?

A. The results of the Company's sales forecast indicate that sales will increase by 4.2 percent and 4.0 percent from October 1, 2005 to September 30, 2006, and from October 1, 2006 to September 30, 2007, respectively.

Q. WILL YOU PLEASE EXPLAIN HOW THE FORECASTS FOR THE PEAK LOAD AND THE ENERGY SALES FOR EACH RATE SCHEDULE WERE DEVELOPED?

A. Yes. The hourly load forecasts developed using the methodology described above were used to develop the coincident peak forecasts. Similarly, the sales forecast developed using the methodology described above were applied to individual rate schedules to forecast energy sales for each rate schedule using the growth rates of sales to the customers on each rate schedule and forecasts of the number of bills for each rate schedule.

Q. DID THE DIVISION SUPPORT OR AGREE WITH ALL OF THE COMPANY'S ADJUSTMENTS?

A. No. Although the Company had reviewed the forecasts for reasonableness and had made the necessary adjustments when needed, the Company failed to document all the adjustments made while developing the forecasts.

Q. HOW DID THE DIVISION DOCUMENT OR VERIFY THE FORECASTS?

A. The Division tried to develop its own forecast to counter check the Company's forecast. In doing so, we used EIA data and applied strictly statistical methods with practically no adjustments.

Q. WHAT WERE THE RESULTS WHEN USING THE DIVISION'S OWN DEVELOPED FORECAST?

A. The results of the Division’s forecast showed that the sales will increase by a more modest amount than the Company’s forecast for the years ending September 30, 2006 and September 30, 2007. As I mentioned in my response to the previous question, the Division used a different model that used strictly statistical methods with very few adjustments.

Q. AFTER THE DIVISION SHARED ITS FORECAST WITH THE COMPANY, DID THE COMPANY PROVIDE THE DIVISION WITH ADDITIONAL INFORMATION AND, IF SO, HOW?

A. Yes. First, the Division shared our forecast information with the Company. Then the Company calculated the impact of this change in the load growth on the revenue requirement and net power cost. Finally, the Company provided the results to the Division.

B. AUDITING ADJUSTMENTS

Q. WHAT DID THE DIVISION DETERMINE TO BE THE MOST SIGNIFICANT FACTOR IN THE RATE CASE?

A. The Division found that the major plant additions accounted for approximately half of the requested increase. Of plant additions, one of the significant additions was the Currant Creek Power Plant. The Division obtained work orders and detailed expenditures to date for Currant Creek. Dave Thomson from the Division sampled the expenditures to assess the appropriateness of their inclusion in the Currant Creek project. The Division also tested the calculation of AFUDC, through its review of Currant Creek expenditures.

Q. WHAT ACCOUNTING ADJUSTMENTS WERE MADE AND HOW WERE EACH OF THOSE PROPOSED ADJUSTMENTS DETERMINED BY THE DIVISION?

A. The Division employed several of our staff members to look at specific accounting adjustments as part of the general audit. The team included Mary Cleveland, Dave Thomson, Carl Mower, and Carolyn Roll. In addition, the Division's John Gothard looked specifically at legal expenses. The Division examined the Company's maintenance and transmission and distribution budgets. The auditors also met with Company officials to discuss the Company's future maintenance requirements and transmission and distribution projects. The attached Excel spreadsheets (Exhibits Nos.

2.3 and 2.4) summarize and detail each of the Division's adjustments and the respective dollar value accompanying each proposed change. The Division's proposed adjustments are discussed below:

- SO_2 Emission Allowances. Consistent with the Commission's Order in Docket No. 97-035-10, the Company amortized SO_2 emission allowance sales over a four-year period. The four-year amortization included forecast SO_2 emission allowance sales through September 2007. The forecast consisted of receipts from the EPA's annual auction of set aside allowances in May 2006 and May 2007. Subsequent to the Company's filing, the May 2006 receipt became known and measurable. The Division made an adjustment to substitute the actual May 2006 receipt in place of the Company's May 2006 forecasted receipt. The Division's adjustment excluded the forecast May 2007 receipt.

- Insurance Expense. The Company's adjustment to insurance expense included an increase to the base year provision for property insurance of $3,114,321, to remove an out-of-period write-down (i.e., credit). However, the $3,114,321 write-down was actually recorded on the Company's books and records in August 2004, outside of the base year, October 2005 to September 2005. Thus, the Division reversed the Company's $3,114,321 adjustment. In addition, the Division made an adjustment to remove pre-October 2003 charges that were actually recorded in the base year. The Division's adjustment only included budgeted insurance expense for the year ending March 2007.

- <u>Incentive Compensation</u>. The Division adjusted incentive compensation to the budgeted level for the year ending March 2007. Additionally, incentive compensation based on the Company's financial performance was removed, consistent with previous Commission orders.

- <u>Challenge Grants</u>. The Division removed Challenge Grants from the forecasted results of operations. Challenge Grants are essentially donations given to various communities throughout the Company's service territory for economic development projects.

- <u>Outside Auditors Expense</u>. This adjustment normalizes expenditures for outsourcing of compliance work to current levels and removes a charge recorded above the line for working with the Internal Revenue Service with respect to a claim for refund of interest for the tax years 1992 to 1994 of PacifiCorp and Subsidiaries.

- <u>FERC Data Quality Business Warehouse</u>. This adjustment removes from the forecasted test year operating expenses expenditures for the development of a robust SAP Business Warehouse reporting capability in the areas of Fixed Assets, FERC PCA, and jurisdictional allocation that should have been capitalized.

Q. WERE THERE ANY OTHER ADJUSTMENTS THAT THE DIVISION FOUND IN ITS AUDITING WORK?

A. Yes. In fact there are eight other areas where the Division made specific adjustments to the Company's filing. They are listed below with a brief explanation for each of the adjustments.

- <u>Capital Stock Costs</u>. The proposed amortization of capital stock expenses by the Company is not permitted by FERC rules or accounting rules. The Division believes the Company would have to have the Commission's permission to do the adjustment that was in their rate case filing for amortizing capital stock costs. They do not have that permission and this adjustment was deleted.

- <u>Sarbanes-Oxley Costs</u>. Per the Company's response to DPU Data Request 12.1, the Company's estimate of Sarbanes-Oxley costs for the 12 months ending September 30, 2007 is $5,293,371. The Division's research indicated that Sarbanes-Oxley costs declined significantly (around 40 percent to 45 percent) after initial implementation. Thus, this adjustment is to normalize this cost in rates.

- RTO Costs. In DPU data request 14.11, we obtained the amount of RTO costs in the forecasted test year expenses. The Division removed these costs because the RTO is gone, and the Company has no regulatory approval for such costs in the future.

- Operational Rent Expenses. The Division adjusted operational rent expenses for closed facilities, vacant space, and under-utilized space. The adjustment was based on information provided to the Division by the Company through formal and informal data requests and by Division analysis and review.

- AFUDC. This adjustment removes from rate base an estimated overstatement of AFUDC as compiled by the Division and the related effects of the reduction to related accounts. Part of the adjustment was the reduction of Idaho's ROE percentage in the AFUDC formula from 13.2 percent to 10.5 percent, which is more representative of current rates. Another part had to do with proper forecasting in future test years of ROE percentages based on the estimated settled rates at the beginning of the year to the estimated forecasted rate amounts the Company used for computing the AFUDC portion of new rate base additions in its rate case. Such rates are higher than currently proposed settlement rates.

- FERC Penalty Expenses. This adjustment was to remove below the line FERC penalty expenses treated as above the line interest expense in the Company's accounting. Upon further review and based upon discussions with the Company, this adjustment has no effect because of the interest synchronization done in the rate case filings. Thus, if settlement had not been reached and the matter proceeded to litigation, we would have withdrawn this adjustment with the caveat that PacifiCorp must be more careful in the future to not include below the line costs in above the line expenses when they do their accounting.

Q. WERE THERE ANY ADJUSTMENTS MADE IN THE AREA OF FUEL STOCK?

A. There were two adjustments recommended in this area, as follows:

- Fuel Stock. The Division does agree that coal stockpiles need to be increased to more prudent levels. For example, the Hunter Plant stockpile was down to approximately 17 days in September 2005. The build up in the rate case includes increases to fuel stock to bring levels back to more prudent levels as well as increasing the stockpile to guard against shortages in the event of labor work stoppages, equipment failure, or railroad delivery interruption. The Division’s recommended adjustment estimates that approximately half of the fuel stock increase relates to increasing the stockpile to more prudent levels. The remaining build up is due to non-recurring events and was adjusted to normalize the build up over a five-year period.

- Mining Plant. The Company's adjustment to mining plant included an increase to the test year for mineral leases totaling $7,000,000. Based on the 13-month average for rate base, only $3,500,000 was included in the test period. This expense is for coal leases that would be acquired from the State of Utah School Trust Lands for future mine development. This expense has been postponed for the previous two years. As a result the Division has deducted the amount included in rates from this case until the expense is certain. When this cost is actually incurred, it can be included in plant for future use and reviewed during the next rate case.

Q. WITH RESPECT TO THE DIVISION'S FINDINGS RELATING TO LEGAL EXPENSES, WILL YOU PLEASE EXPLAIN THE ADJUSTMENTS THAT THE DIVISION PROPOSED?

A. Yes, there were basically three areas in the area of legal expenses where the Division proposed adjustments: normalization, denial of escalation of test period, and prudence.

Q. WILL YOU EXPLAIN THOSE ADJUSTMENTS?

A. The Division compared legal expenses for the base period ending September 30, 2005, to the average for the three previous twelve-month periods ending September 30, 2002, 2003, and 2004 to determine whether the expenses were consistent with the average. The test period expenses were greater than the calculated three-year average. Therefore, we made an adjustment to normalize the Company's legal expenses for the base period ending September 30, 2005, based on the previous three-year average.

The Division also proposed an adjustment to disallow any escalation of the base period legal expenses based on the Company's current rebasing project and expressed intention to cut its use of outside services to reduce expenses. This formed the basis for our escalation adjustment. Due to the Company's intentions, an adjustment was made to disallow ten percent of the adjusted base period legal expense. This adjustment assumes that the prudent reduction of outside services should be equivalent to 10 percent.

Finally, salaries and employee benefits were carefully examined, due not only to PacifiCorp's Rebasing Program, but to changes being implemented immediately subsequent to MidAmerican's acquisition.

C. RETURN ON EQUITY

Q. PLEASE DESCRIBE THE DIVISION'S ANALYSIS WITH RESPECT TO RETURN ON EQUITY ("ROE")?

A. The Stipulation indicates that the authorized ROE is 10.25 percent. This is a 25 basis point reduction from the current cost of equity. The Division determined that 10.25 percent is within a reasonable range for an authorized return on equity. An authorized

ROE of 10.25 percent was one of the numbers within a range of values that the Division used to evaluate the settlement revenue requirement of $115 million.

Q. PLEASE PROVIDE A DETAILED EXPLANATION OF HOW THE DIVISION ARRIVED AT THIS DETERMINATION.

A. Charles Peterson will be presenting testimony for the Division on the cost of capital and the related capital structure issues (DPU Exhibit No. 3.2). I should emphasize that, other than the 10.25 percent ROE as presented in the Stipulation, the Division is not asking the Commission to make a finding regarding any cost of capital methodologies or related results in this matter. We are not asking the Commission to adopt or approve any specific methodology that was used to arrive at a 10.25 percent ROE, but are asking that the number itself–10.25 percent–be approved in this case. I will briefly summarize the Division's analysis and position on this matter.

The Division reviewed and analyzed the testimonies of PacifiCorp witnesses Bruce N. Williams, the Company's Treasurer, and Samuel C. Hadaway, Ph.D., an outside expert. Mr. Williams provided testimony regarding cost of debt, cost of preferred stock, and capital structure. Dr. Hadaway filed testimony on cost of equity. The Division also began its own, independent evaluation of these issues, particularly with respect to cost of equity.

Q. WHAT WAS THE COMPANY'S ORIGINAL FILED POSITION REGARDING COST OF CAPITAL?

A. The Company asked for the following cost of capital rates of return: Long-term Debt, 6.41 percent; Preferred Stock, 6.54 percent; Common Stock, 11.40 percent. The following capital structure was also requested: Long-term Debt, 46.2 percent; Preferred Stock, 1.0 percent; Common Stock, 52.8 percent.

Q. AS MENTIONED ABOVE, THE STIPULATION SPECIFIES 10.25 PERCENT FOR THE RETURN ON EQUITY. HOW DOES THE DIVISION VIEW THE OTHER COMPONENTS OF THE COST OF CAPITAL?

A. Other than the stipulated 10.25 percent return on equity, the other components of cost of capital are not specified in the Stipulation, nor are the other Parties to the Stipulation necessarily in agreement as to what amounts those other components should be. However, the Division in judging the settlement to be reasonable used the following: Long-term Debt, 6.41 percent; Preferred Stock, 6.54 percent; Common Stock, 10.25 percent. The following capital structure was assumed by the Division: Long-term Debt, 47.0 percent; Preferred Stock, 1.0 percent; Common Stock, 52.0 percent.

Q. ASIDE FROM THE DIFFERENCE IN THE RETURN ON EQUITY, THE OTHER CAPITAL COST ITEMS AND THE CAPITAL STRUCTURE ARE

ABOUT WHAT THE COMPANY REQUESTED. DO YOU HAVE ANY COMMENTS ABOUT THIS SIMILARITY?

A. Yes. As Mr. Peterson will explain, the Division determined that the cost of long-term debt and of preferred stock were within the reasonable range for settlement. Likewise, with the exception of a small change in the requested capital structure (going from 52.8 percent equity to 52.0 percent), the requested capital structure was determined to be reasonable.

Q. NOW WE ARE BACK TO THE COST OF EQUITY. PLEASE SUMMARIZE HOW THE DIVISION DETERMINED THAT 10.25 PERCENT WAS "WITHIN A REASONABLE RANGE."

A. Mr. Peterson examined a number of models in order to arrive at range of cost of equity estimates. (Please refer to Peterson Testimony, DPU Exhibit 3.2.) The models included the traditional DCF model and three risk premium models. As can be seen from this Exhibit, 10.25 percent falls easily within the range of averages of the models with the exception of the Discounted Cash Flow (DCF) model. In the DCF models that Mr. Peterson examined, 10.25 percent is in the upper half of the range of values calculated for the individual guideline companies. The DCF model that produced a 10.42 percent average is based upon historical growth rates with any individual company producing a result below 7.40 percent eliminated from consideration.

Although 10.25 percent is in the upper half of its calculated range, based upon this information, the Division concludes that the 10.25 percent ROE is reasonable and therefore supports the adoption of 10.25 percent in the Stipulation.

D. NET POWER COSTS

Q. WHAT IS THE RANGE OF NET POWER COSTS ("NPC") USED TO REACH THE DIVISION'S SETTLEMENT RANGE?

A. The range used by the Division to determine that the settlement reached by the Parties is reasonable is a total Company NPC of $783.5 million to $777 million. This number is approximately $29.5 to $36 million lower than the NPC of $813 million contained within the Company's March 7, 2006 rate case filing. On a Utah basis, using a 42 percent allocation factor, the lower NPC number supported by the Division leads to a $12.5 to $15 million decrease in the Company's filed case.

Q. WHAT COSTS OR MODEL INPUTS WERE CHANGED TO ARRIVE AT THE RANGE DESCRIBED ABOVE?

A. The Division made a series of changes to the GRID model. In no particular order, these changes are as follows:

- The output of the Foote Creek plant was increased to better approximate the five-year average actual production.

- The QF plant called Desert Power was removed from the first eight months of the test year in order to more accurately reflect the current assumptions regarding its online date. The contract with the plant, upon which the original modeling was based, calls for an online date of June 1, 2006. At the time that the rate case settlement was reached, this date was thought to be sliding to June 1, 2007.

- The contract with Nucor Steel for operating reserves was extended through the end of the test year. Its end date in the original filing was December 31, 2006.

- The end dates for the QF contracts for Kennecott and Tesoro were extended to reflect the most up-to-date information available. Pricing for these contract extensions reflects the most current estimated QF pricing available.

- The SMUD contracts were removed from the model due to prior Commission rulings and ongoing questions regarding prudence.

Q. WILL YOU PLEASE BRIEFLY DESCRIBE THE EXAMINATION UNDERTAKEN BY DIVISION PERSONNEL IN ORDER TO DETERMINE THAT THE AFOREMENTIONED ADJUSTMENTS PRODUCE A REASONABLE NET POWER COST?

A. Division personnel examined the inputs to the GRID model, examined supporting data provided in response to numerous data requests, and made nearly 30 model runs of various scenarios. Division personnel also held technical discussions with PacifiCorp personnel and other stakeholders in order to obtain input and information.

Q. DOES THE DIVISION BELIEVE THAT THIS NPC RANGE IS A REASONABLE FORECAST OF THE COSTS THAT PACIFICORP MAY FACE DURING THE FORECASTED PERIOD?

A. Yes. The range of NPCs described above represents what the Division believes to be a reasonable forecast of PacifiCorp's future power costs. The Division's intent in determining this forecast was twofold–to offer the Company a reasonable opportunity to cover prudently incurred costs during the test period, while providing a tight budget to encourage the Company to control its costs. The Division’s examination of the aforementioned adjustments resulted in reasonable NPC results.

E. RATE SPREAD

Q. WITH RESPECT TO THE RATE SPREAD ELEMENT, WILL YOU PLEASE DESCRIBE WHAT WAS STIPULATED TO?

A. Yes. There are basically two main areas that the Division and the Parties agreed to. First, we agreed to the allocation of revenues to customer classes as described in

PacifiCorp's Exhibit 1 to the Stipulation. I will describe those in further detail later. Second, the Parties agreed that, for the purposes of revenue allocation in this case, no rate increase revenues will be allocated to special contract customers. Any rate change provisions contained in special contracts will remain intact. The Division is not asking the Commission to make a finding regarding rate spread. However, I will briefly summarize the Division's analysis and position on this matter.

Q. WILL YOU PLEASE EXPLAIN WHAT WAS SPECIFICALLY CONTAINED IN EXHIBIT 1 TO THE STIPULATION, AND THEN DESCRIBE THE DIVISION'S JUSTIFICATION FOR ADOPTING THE RATE SPREAD DESCRIBED ABOVE?

A. Yes. The outcome of the Stipulation, as reflected in PacifiCorp's Exhibit 1, was to give Schedule 6 (large general service) a 6.24 percent increase while the overall average was 4.66 percent. The larger increase to Schedule 6 enabled other major schedules (1, 9, 23) to receive an increase of only 3.8 percent. The Division agreed with PacifiCorp's recommendation in this case that, in order to justify a departure from the standard increase, which in this case is 10.31 percent, there must be a disparity beyond the plus or minus 10 percent zone within the rate of return index. In addition, departures from the standard figure might be notably smaller–just one percent in the case of Schedule 6.

While the PacifiCorp cost of service studies in the previous rate case did not show Schedule 6 (large general service) as having a rate of return index below 0.90, it was the lowest of the major schedules (1 - Residential; 8 - General Service over 1 MW; 9 - High Voltage; 23 - Small General Service), and dropped well below 0.90 in cost of service studies that formulated the cost allocations on the basis of four or fewer monthly coincident peaks rather than the standard 12.

Q. HOW HAS THE COMMISSION DETERMINED THE RATE SPREAD ELEMENT IN PRIOR CASES?

A. In prior decisions the Commission has used a rate of return index to determine which classes should receive more or less than the average rate increase (or decrease). Each class's index was obtained by dividing its projected return on rate base (given no rates change) by the system average return on rate base. If the calculated index was between 0.90 and 1.10, the schedule was expected to receive the same increase as most of the other schedules.

Q. IN THE STIPULATION, WERE THERE ANY SCHEDULES WHERE THE RATE OF RETURN INDEXES VARIED FROM UNITY AND RECEIVED AN OUTCOME OTHER THAN THE 10.31 PERCENT NORM? IF SO, PLEASE EXPLAIN WHY.

A. There was only one departure under the Stipulation where the rate of return indexes varied substantially; and we, therefore, assigned an increase other than the 10.31 percent norm. It was the case of Schedule 9, which is comprised of very large and/or high voltage customers. The Division found disparate results for Schedule 9 in this case's cost of service study.

Q. WHAT WERE THE ARGUMENTS FOR GIVING SCHEDULE 9 THE STANDARD INCREASE?

A. First, establishing demand costs on the basis of fewer monthly peaks reduces Schedule 9's cost allocation. UIEC presented evidence to this effect in the prior general rate case. Offsetting this result is the argument that baseload coal plants' cost should be classified as no more than 50 percent demand-related rather than the current 75 percent. Re-classifying those costs as energy-related shifts costs to the high load factor customers, particularly Schedule 9.

Second, recognizing that the underlying rationale behind substituting a 1.375 percent-over-Rolled In revenue requirement for that generated under the Revised Protocol, produces lower generation costs, thereby favoring Schedule 9.

Third, attributing a disproportionate share of the costs of the generation planning reserve margin to customer classes whose peak loads are more weather-sensitive and therefore less predictable reduces the allocation to Schedule 9.

The fourth and final argument is the fact that the Schedule 9's rate of return index was within the plus-or-minus 10 percent band in the previous case, but moved so far beyond it in this case, creating a certain amount of skepticism regarding the cost of service results for that Schedule. That movement occurred despite the substitution in this case of a weighted 12 coincident peak demand allocator in lieu of an unweighted factor, thereby allocating more of the generation and transmission demand costs to the residential and commercial classes, whose demands are more seasonal than are Schedule 9s.

Q. DO THE DIVISION'S ANALYSIS AND FINDINGS CONTRADICT PRIOR COMMISSION DECISIONS REGARDING THE RATE OF RETURN INDEX?

A.. The answer to this question depends on one's judgment. Let me explain. When general rates are adjusted up or down, the tendency is *not* to develop class cost allocations, i.e., rates spreads, that produce equal rates of return, but rather to give each class the same percentage change as are given to all the rest unless such would result in a class earning far above or far below the system average. Judgment comes in deciding what constitutes "far," and what degree of adjustment should be made as compensation. Such judgments were implicit in the resolution of the rates spread component in the Stipulation in this case. Therefore, we think the Division's judgment of the rate spread is reasonable and is not contradictory.

Q. ARE THERE ANY OTHER SCHEDULES THAT YOU WOULD LIKE TO MENTION IN THE RATE SPREAD CONTEXT?

A. Yes. The Stipulation proposes that Schedule 23 receive a 1 percent smaller increase than the standard 10.31 percent. The Stipulation also proposes that the minor schedules, except for Schedule 2–residential optional time-of-day, receive increases that are 2 percent above or 2 percent below the 10.31 percent norm.

Q. I UNDERSTAND THAT THE PARTIES WERE NOT ABLE TO REACH AN AGREEMENT WITH RESPECT TO RATE DESIGN AND THESE ELEMENTS WERE NOT INCLUDED IN THE STIPULATION. IS THIS CORRECT?

A. Yes. The Parties are still discussing issues, and the negotiations continue.

V. SUMMARY OF DIVISION ADJUSTMENTS FOR SETTLEMENT PURPOSES

Q. NOW THAT YOU HAVE EXPLAINED ALL OF THE DIVISION'S WORK AND ANALYSIS ON THIS CASE, WILL YOU PLEASE SUMMARIZE EACH OF THE ADJUSTMENTS IN DOLLAR VALUES?

A. Yes, I have attached two Excel spreadsheets that summarize each step that led the Division to its final settlement range (Exhibits 2.3 and 2.4). The summary exhibit shows, line by line, each dollar value and accompanying adjustment. The Company's updated filing position was $194,000,000. Then, we subtracted the settlement adjustment agreed upon for capital costs (10.25 percent and 52 percent) of $37,500,000 to arrive at a revenue requirement of $156,500,000. We then subtracted the $30,000,000 scheduled for the second phase in June 2007. This left a dollar value of $126,500,000 from which each specific Division adjustment was made.

Q. HOW DID THE DIVISION ARRIVE AT THE HIGH END OF THE RANGE?

A. In Exhibit No. 2.3, which calculates the high end of our settlement range, the line-by-line auditing adjustments are listed next, in columns by total company, Utah allocated, and rolled-in cap (1.5 percent). The high end of the range has an assumption of a NPC adjustment of $12,500,000. Then the auditing adjustments, including NPC, totaled $25,226,023. Subtracting the high end auditing adjustments of $25,226,023 from the $126,500,000 base resulted in $101,273,977. Adding back in the second phase $30,000,000 scheduled for June 2007, as well as including a net present value benefit of the $30,000,000 deferred for one half year at 8.5 percent, resulted in $130,074,899. Then two additional assumptions were made: (1) an additional $3,000,000 in adjustments from other Parties would be accepted; and (2) the value of a stay out was also $3,000,000. With this, the Division arrived at $124,074,899 for the high end of its settlement range.

Q. HOW DID THE DIVISION ARRIVE AT THE LOW END OF THE RANGE?

A. Exhibit No. 2.4 calculates the low end of our settlement range and assumes a NPC adjustment of $15,000,000. Then the auditing adjustments, including NPC, totaled

$27,763,523. Subtracting these low end auditing adjustments from the $126,500,000 base resulted in $98,736,477. Again adding back in the second phase $30,000,000 scheduled for June 2007, as well as including a net present value benefit of almost $1,200,000, resulted in $127,537,399. The two additional assumptions for the low end of the range were: (1) an additional $10,000,000 in adjustments from other Parties would be accepted; and (2) the value of a stay out was also $10,000,000. With this, the Division arrived at $107,537,399 for the low end of its settlement range.

Q. **HOW DOES THE $115 MILLION REFERRED TO IN THE STIPULATION COMPARE TO THE DIVISION'S SETTLEMENT RANGE?**

A. The settlement range the Division used, rounding to the nearest million dollars, was $108 to $124 million. The simple average of the low and high ends of this range is $116 million. The Division used this procedure and its assumptions in the context of settlement negotiations. The Division concluded that the $115 million as specified in the Stipulation was within its settlement range of $108 to $124 million.

V. CONCLUSION

Q. DO THE TERMS OF THE STIPULATION MEET THE PUBLIC INTEREST TEST?

A. Yes. As I have described above and in the supporting Exhibits that follow my testimony, the Division identified a number of items early on for which adjustments were made or negotiations took place. The Stipulation itself specifies the entire list of items and terms of the Stipulation that the Parties (including the Division), agreed upon, including: revenue requirement, rate credit, rate spread, retail load forecast, next rate case, PCAM, filing requirements, fuel expense, solar program, regulatory assets, and finally, Utah System Maintenance and Capital Expenses. As I described earlier, the Division's supporting calculations are contained in this Testimony and/or the attached Exhibits.

The Division finds that the final terms and conditions of the Stipulation, taken as a whole, serve the public interest and are just and reasonable as required by Utah Code Ann. § 54-3-1. The Division also finds that the terms of the Stipulation will allow the Company to have sufficient revenue to recover the reasonable costs of providing electric service in the state of Utah.

Q. WHAT HAS THE DIVISION CONCLUDED AND WHAT DO YOU RECOMMEND IN THIS DOCKET?

A. Based on our investigation and analysis, the Division concludes that the proposed Stipulation balances the interests of all parties in this matter and, therefore, is just and reasonable and in the public interest. The Division recommends that the Stipulation be approved.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.