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, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge	**)))))))))**	**Docket No. 07-035-93** **DPU Exhibit No. 5.0**

Direct Testimony of

Mark E. Garrett

REVENUE REQUIREMENT

For the Division of Public Utilities

Department of Commerce

State of Utah

April 7, 2008

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Direct Testimony of Mark E. Garrett

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Mark E. Garrett. I am an independent consultant specializing in public utility regulatory issues.

Q. What is your business address?

A. Two Leadership Square, Suite 340, 211 North Robinson Avenue, Oklahoma City, Oklahoma 73102.

Q. On whose behalf are you appearing in these proceedings?

A. I am testifying on behalf of the Division of Public Utilities ("Division").

Q. Please describe your educational background and professional experience related to utility regulation.

A. I received my bachelor's degree from the University of Oklahoma and completed post graduate hours at the University of Texas and Stephen F. Austin State University. I received my juris doctorate degree from Oklahoma City University Law School and was admitted to the Oklahoma Bar in 1997. I am a Certified Public Accountant licensed in the States of Texas and Oklahoma with a background in public accounting, private industry, and utility regulation. In public accounting, as a staff auditor for a firm in Dallas, I primarily audited financial institutions in the State of Texas. In private industry, as controller for a mid-sized ($300 million) corporation in Dallas, I managed the company's accounting function, including general ledger, accounts payable, financial reporting, audits, tax returns, budgets, projections, and supervision of accounting personnel. In utility regulation, I served as an auditor in the Public Utility Division of the Oklahoma Corporation Commission from 1991 to 1995. In that position, I managed the audits of major gas and electric utility companies in Oklahoma. Since leaving the Commission, I have worked on various rate cases and other regulatory proceedings on behalf of industrial interveners, large commercial customers, cities, gas pipelines, and the Attorney General of Oklahoma.

Q. Have you previously testified before this Commission?

A. No. This is my first occasion to testify for the Division.

Q. Have you testified before other commissions and were your credentials accepted in those proceedings?

A. Yes. I have testified in regulatory and civil proceedings and my qualifications as an expert in utility ratemaking matters have been accepted. A more complete description of my qualifications and a list of the proceedings in which I have been involved are included in Attachment 1 at the end of my testimony.

II. PURPOSE AND RECOMMENDATION

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

A. My testimony presents the Division's position regarding several revenue requirement issues in this case. I also explain the basis for these positions and provide analysis in support of my proposed adjustments and recommendations.

Q. What specific issues will you address in your testimony?

A. I will address Rocky Mountain Power's ("Company") proposed Cash Working Capital Allowance, Payroll Expense, Incentive Compensation and the PowerDale decommissioning.

III. CASH WORKING CAPITAL

Q. Please describe the Company's requested allowance for Cash Working Capital?

A. The Company requested a Cash Working Capital allowance of $31,688,954 for the Utah jurisdiction.[1] The Company's request is based on a March 2003 lead-lag study with one additional adjustment included for lag days associated with federal income tax payments.

Q: What is Cash Working Capital?

A: Cash Working Capital ("CWC") is often defined as the net cash outlay that a utility must furnish to provide service before payment for that service is received from customers. However, it is common today for a major utility to receive payments from its customers before the various obligations of the company to its vendors and employees that relate to those services become due. This creates a situation where the customers are actually supplying the company with cost-free capital, and a reduction to rate base is appropriate in these situations. A utility company's ability to negotiate large contracts advantageously, coupled with its utilization of sound cash management techniques will, in many situations, produce a negative CWC requirement.

Q: How does one determine whether customers or investors actually supply the utility's operating capital?

A: A lead-lag study is the most accurate method available to determine whether the company or the customer actually provides the cash that pays the bills for the day-to-day operations of the company. A lead-lag study compares the timing differences between the inflows of cash from revenues and the outflows of cash for operating expenses. The net difference is

[1] Supplemental Exhibit RMP_(SRM-1S), tab 2.33

expressed as a positive cash requirement if the company is supplying cash to pay its day-to-day operating expenses before payments for these services arrive from customers, and as a negative cash requirement if payments from customers actually arrive before the company is obligated to pay its various expenses. These differences are expressed in the number of days between the time the company pays its bills and the time the customers remit their payments.

Q. Do you agree with the Company's requested CWC allowance.

A. No. The 2003 lead-lag study utilized by the Company does not provide a reasonable basis for determining the Company's current CWC requirements. A utility can experience significant internal and external changes in a five year period that materially impact its collection and payment practices. These changes might include increased attention to slow paying customers or stricter adherence to termination procedures. They could also include renegotiated payment terms on important supply contracts. Changes in technology, such as automated payment options for customers, could also have a significant impact. Changes in the overall economic conditions of the area could make a difference, as could overall customer satisfaction with service and reliability. These changes are material and their impact on the CWC requirement can only be quantified with a current lead-lag study. It is inconsistent for the Company to argue on the one hand that an historic test year is too out-dated to use for setting prospective rates, and then, on the other hand, ask that it be allowed to use a five year old lead-lag study to support a significant CWC allowance.

Q. Has the Company's 2003 study been accepted in any of the other PacifiCorp jurisdictions?

A. No. In response to DPU Data Request 22.7, The Company's states that all the cases since the preparation of the 2003 study have been stipulated settlements with the exception of the 2005 docket in Washington.

Q. Did the Washington Commission accept the 2003 study?

A. No. The Washington order cites the same concerns raised in this testimony. At paragraph 186, the order states:

> [T]he 2003 lead-lag study upon which the Company relies in its testimony and argument, does not appear in the record in this proceeding. Even if we were to accept the lead-lag method, we have no way to determine whether the Company's study is valid and <u>sufficiently current</u>. (Emphasis added).

In paragraph 189, the Commission further states:

> We do expect that a company using a lead-lag study, or any other method, will submit the study for the record so that Staff, interveners, and ultimately the Commission, can determine whether the study is valid, <u>current</u>, accurate and appropriate. (Emphasis added).

Q. Did the Company submit a lead-lag study in this case that could be reviewed?

A. No. What the Company provided was a <u>summary</u> of the results from the 2003 study. The underlying data supporting the calculations were not included. This is understandable since the data are now five years old. Without being able to trace to the original source documents – invoices, cancelled checks, payment vouchers, wire transfers, contracts, accounts payable journals, accounts receivable registers, etc. – an auditor cannot test the validity or reliability of the calculations or the conclusions reached in the study.[2] Further, since the study has not

[2] For example, at page 4.0.4 the Study states with respect to the Accounts Payable data that "Due to the large size of the file, only the first and last pages of the report are included." Even if the entire report had been included, the original source documents would still not be available to trace and audit. Moreover, the PacifiCorp employee who performed the 2003 study is no longer with the Company and could not be interviewed.

been accepted by any commission, an auditor cannot rely on third-party validation to gain a comfort level that the study was ever sufficiently tested and verified. Moreover, an auditor cannot ascertain whether the conclusions reached in 2003 are still valid today. Short of performing a new study using available data, there is no way to quantify the Company's CWC needs with any degree of reliability.

Q. Is Division Staff responsible for quantifying the Company's actual current CWC needs?

A. No. Certainly the burden remains with the applicant to sufficiently support its requested increase for CWC.

Q. Are there items in the 2003 Lead-lag summary that seem out of line?

A. Yes. The item with the single greatest impact in a lead-lag study is the Revenue Lag days. This is the number of days it takes for the utility to receive customer payments. The Revenue Lag in the Company's study for Utah is 44.82 days. This seems high when compared with other utilities. For example, Utah is higher than any of the other PacifiCorp states.[3] The Company's 44.82 days for Utah is also much higher than the revenue lags I have seen submitted by other utilities in recent rate cases. Oklahoma Gas & Electric submitted 39.47 days.[4] Entergy Texas submitted 39.00 days**,**[5] Southwestern Public Service 41.83 days.[6] These differences are material. In today's environment, 44.82 revenue lag days seems excessive. Technological advances in metering and automated banking alone have shortened

[3] Idaho is 40.56, Wyoming is 40.23.
[4] See Cause No. PUD 200500151.
[5] See PUC Docket No. 34800.
[6] See PUC Docket No. 37766.

the collection time for most utilities. It is impossible, though, to tell if the Company has had similar success because it has not filed current results.

Q. The Company compares its use of the 2003 lead-lag study to using the results of a depreciation study for several years until a new study is performed.[7] Is this a valid comparison?

A. No. Lead-lag studies and depreciation studies are different in a number of significant ways that make this an invalid comparison.[8] However, the most important and relevant distinction here is that a depreciation study is actually <u>accepted</u> by a commission before it is implemented for ratemaking purposes. In other words, depreciation rates are established by commission order, and those rates stay in place until new rates are ordered. In contrast, the Company's 2003 lead-lag study has never been accepted by this Commission or by any other commission. This lack of official validation further weakens the legitimacy of the study. Even with validation, though, the study is too old to be useful.

Q. In the absence of a valid lead-lag study, how is the CWC allowance treated?

A. A lead-lag study is generally required to support a positive CWC allowance. In the absence of a reliable study, commissions generally set the CWC allowance at zero.

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[7] See RMP response to DPU 22.11.

[8] From a ratemaking perspective the analogy is weak because shareholders are financially indifferent to variances in depreciation rate recoveries. Depreciation is merely the return of invested capital over some period of time, during which, the utility earns a return on the un-recovered investment balance. Shareholders are not financially indifferent to CWC allowances. To the contrary, CWC can be a significant profit center, since the allowance is included in rate base where it earns a return. The risk for ratepayers is that this treatment actually provides a disincentive for the utility to optimize its cash management practices. This built in disincentive should cause commissions to view with some skepticism utilities that claim to have a positive CWC requirement, when the timing of cash receipts and disbursements is largely in the utility's control. In the competitive environment, a positive CWC requirement would decrease earnings. Thus, in the competitive environment, a positive CWC requirement due to poor cash management would be quickly corrected. For the regulated utility, the opposite is true. Since a positive CWC requirement actually increases earnings, a similar urgency to maximize the timing of cash receipts and disbursements does not exist.

Q. Is there precedent for the position that the CWC allowance should be set at zero in the absence of a reliable lead-lag study?

A. Yes. From my experience, commissions require that a positive CWC request be supported with a comprehensive and contemporaneous lead-lag study. I know that Oklahoma, Kansas, Texas, and Nevada all follow this rule. Without a lead-lag study, the allowance is set at zero. In Texas, the rule is more onerous, however. In Texas, the utility is required to recognize a <u>negative</u> CWC requirement equal to 1/8 of its O&M expense if a reliable lead-lag study is not provided.

> **<u>§25.231(c)(2)(B)(iii)(IV)</u>**
>
> (IV) For all investor-owned electric utilities a reasonable allowance for cash working capital, including a request of zero, will be determined by the use of a lead-lag study.
> (V) If cash working capital is required to be determined by the use of a lead-lag study under the previous sub-clause and either the electric utility does not file a lead lag study or the electric utility's lead-lag study is determined to be so flawed as to be unreliable, in the absence of persuasive evidence that suggests a different amount of cash working capital, an amount of cash working capital <u>equal to negative one-eighth of operations and maintenance expense</u> including fuel and purchased power will be presumed to be the reasonable level of cash working capital. (Emphasis added).

The Texas rule actually presumes that a utility's normal CWC requirement is negative. The utility must prove the requirement is not negative with a reliable lead-lag study.

Q. Are there other states with specific regulations that require a current lead-lag study?

A. Yes. The Iowa administrative code at 199 IAC 26.5(5) sets forth the specific evidence a utility must submit with its application to change rates. To support its CWC request a utility must submit "a recent lead-lag study which accurately represents conditions during the test period."[9] (Emphasis added).

Q. Is there precedent for ignoring the results of an out-dated lead-lag study?

A. Yes. In a 2001 rate case, Nevada Power included a CWC allowance in its application based on a 1998 lead lag study performed for its sister utility Sierra Pacific, asserting that the collection and payment practices of the two utilities were virtually identical. I testified that the results of the 1998 study were not reliable and the company's CWC allowance should be set at zero. The Nevada Commission agreed, finding that NPC had "not supported its request for CWC with a valid lead-lag study."[10]

Q. In your experience, have you ever seen a utility submit an outdated lead-lag study to support a CWC allowance?

A. No. In the states where I regularly practice, Okalahoma, Texas, and Nevada, the utilities provide, as a matter of course, a current lead-lag study based on test year data for each rate case proceeding.[11] I do not recall ever seeing an out-dated study, other than in the Nevada Power case where the study was rejected.

Q. How many rate case proceedings have you testified in where a lead-lag study was submitted?

A. I recall being involved in approximately seventeen rate cases where a lead-lag study was submitted to support a CWC allowance. In many of those cases, the allowance was negative. In every case, other than one, the study was current.

[9] See 199 IAC 26.5(5)e(5).
[10] See Final Order in Docket 01-10001, page 31. There is no Nevada statute of Commission rule addressing the issue. The Nevada Commission relied on the testimony of Staff and the MGM Mirage in reaching its decision.
[11] Lead-lag studies generally cover the test year or a portion of the test year.

Q. What is your recommendation to the Commission on this issue?

A. I believe the Commission should set a high standard for including CWC in rate base. This approach protects ratepayers against the inherent incentive that would otherwise exist for a utility to turn its cash management practices into a profit center. In the absence of specific rules, I believe the Commission should require, as a policy, that utilities file a contemporaneous lead-lag study to support a positive CWC request. The 2003 lead-lag study submitted to support the Company's request in this case does not use current data and the underlying data that was used could not be tested for validity or reliability. Since the 2003 study was never accepted by this Commission or any other commission, the Company cannot point to a time when the study was ever shown to be valid, even when the data were fresh. In this proceeding, I recommend the Commission reject the Company's request to include $31,688,954 in rate base for CWC. Instead, the CWC allowance should be set at zero. The Company states that it is performing a 2007 lead-lag study.[12] In its next rate case, the Company can submit its 2007 study, if the study is sufficiently current at that time, to support a CWC request.

IV. PAYROLL AND RELATED EXPENSES

Q. Please describe the Company's payroll expenses and the adjustments related to these costs?

A. Employees costs are the second largest category of expenses in the revenue requirement after net power costs. The Company is proposing to recover nearly $232 million from Utah ratepayers for labor expenses, benefits, and payroll taxes. This amount includes Company

[12] See RMP responses to DPU 22.09 and DPU 22.11.

adjustments for scheduled bargaining labor increases and budgeted increases for non-bargaining labor as well as budgeted levels of incentive payments and benefit costs.

Q. What problems did you find with the Company's payroll adjustments?

A. The Company used scheduled and budgeted payroll increases to make its adjustments to direct payroll. While it may seem apparent that pay raises implemented after the test year would increase payroll expense, what may not be so apparent is that other events over the same period could decrease payroll levels by even greater amounts. For example, workforce reductions can have a far greater impact on payroll expense than a pay raise would. And other, more subtle, changes can decrease payroll levels as well. For example, even with a stable workforce, employees are being added to, and taken off, the payroll registers on a fairly regular basis. Since retiring employees are generally paid much more than new hires, overall payroll expense levels can decrease significantly if a number of higher paid employees leaving the company are replaced with employees paid at lower levels. Changes in a company's capitalization percentages during a period of higher construction can also reduce payroll expense levels, even with no reduction in overall payroll costs. Each of these potential reductions in payroll expense can more than offset the anticipated increase from an annual raise. As a consequence, even if the Commission were inclined to accept an adjustment to payroll levels, the Company's proposed adjustment is inappropriate because it fails to show that net payroll expense levels will actually increase by the amount of the estimated pay raise. In short, the Company's proposed adjustment does not satisfy the *known and measurable* standard for adjustments to test year expense because the Company failed to properly measure the level of adjustment.

Q. Why is the Company's proposed adjustment deficient with respect to the *known and measurable* standard?

A. The Company's proposed adjustment is deficient because the Company has not shown that its 2.25% scheduled increases actually result in a 2.25% increase in payroll expense. In other words, the increase may be known, but the Company has not measured its impact on operating expense.

Q. Did you perform any analysis of the actual impact the budgeted raises may have on payroll expense?

A. Yes. I reviewed the Base Year payroll costs and the scheduled and budgeted raises for that period. After adjusting the payroll data for the MEHC adjustment,[13] I looked at payroll levels both before and after the scheduled raises. From this review, I found that payroll costs increased for <u>bargaining employees</u> after the scheduled raises, but payroll costs actually decreased for the three groups of <u>non-bargaining employees</u> after the raises were implemented.[14]

Q. As a result of this finding, what changes do you recommend to the Company's proposed payroll annualization?

A. I recommend that the Base Year raises for the <u>non-bargaining employees</u> be excluded from the Base Year labor annualization adjustment. This adjustment reduces Base Year payroll for the first six months of the Base Year for non-bargaining employees by 2.21%, which

[13] The MEHC transition adjustment removed the costs of the workforce reduction that accompanied the purchase of PacifiCorp by MEHC.
[14] This overall decrease was the result of additional attrition among management level employees after the MEHC adjustment. As discussed above, pay raises alone are not the only factor that impact overall payroll levels. Changes in the composition of the workforce must also be taken into account.

reduces Base Year payroll expenses by $3,269,182 on a total Company basis, and $1,397,616 for the Utah jurisdiction.

Q. Do you recommend any changes to the Test Year labor adjustment proposed by the Company?

A. Yes. The Company failed to consider overall improvements in productivity in its proposed adjustment. These productivity improvements must be considered in forward looking adjustments to payroll costs. While the Company considered incremental increases to specific components of payroll, it did not include the mitigating affects of increased productivity.

Q. What is productivity growth and why is it important in this case?

A. In economic terms, productivity is the ability to produce more with less input. Productivity is measured by comparing the amount of goods and service produced with the inputs used in the production of a product. Specifically, labor productivity is the ratio of the output of goods and service to the labor hours devoted to the production of the output. Labor productivity, as reported by the Bureau of Labor Statistics ("BLS"), indicates significant growth in labor productivity over the past few years.

Q. Why is labor productivity important in this case?

A. Labor productivity is important here because of the use of a forecasted test year. An accurate projection of labor costs will give some recognition to the expectation of increased productivity.

Q. Please explain your labor productivity adjustment.

A. My adjustment utilizes the Company's projected payroll increases for the forecast test year but makes an additional mitigating offset for increased productivity. This labor productivity offset recognizes the fact that the Company will continue to seek labor productivity gains in the future, just as it has in the past. My actual productivity adjustment reduces total company labor cost by 1% per year, or about 1.5% for the 18 month forecasted period. This is a modest estimate of the labor efficiencies the Company should expect to achieve. The BLS reported "business sector" productivity growth of 1.9% for 2007, 1.0% for 2006, and 2.0% for 2005. This results in a 3-year average productivity growth of about 1.6%. The past 2-year average is 1.45%. To be conservative, I used a productivity estimate of 1.0% for my adjustment. Offsetting the Company's projected labor cost increases with a 1.0% per year productivity factor results in a reduction in payroll expense of $5,623,544 on a Total Company basis, and $2,404,135 at the Utah jurisdictional level.

Q. Does BLS report labor productivity more specific to the electric utility industry?

A. Yes. BLS gathers and reports labor productivity for the electric power generation, transmission and distribution industry. However, the "electric utility sector" information is not as current as the "business sector" data quoted above. The electric industry information ends with the year 2005. Starting with the most recent available year, labor productivity for the electric utility industry was 6.2% for 2005, 2.2% for 2004 and 2.1% for 2003. The electric utility productivity has been increasing in recent years and has outperformed general business sector productivity growth. In light of this trend, my use of the 1.0% factor is conservative.

Q. Are you aware of any other sources indicating a strong electric utility industry productivity factor?

A. Yes. In a January 2006 report prepared for the Edison Electric Institute, the Pacific Economics Group stated that "productivity growth of electric utilities has been generally equal to or superior to that of the economy as a whole in the last twenty years."[15]

Q. Please summarize your adjustments to the Company's forecasted labor costs.

A. The combined impact of the labor adjustments on pro forma operating expense is a reduction of $3,801,175. This number consists of a Base Year payroll adjustment of $1,397,616 and a Test Year productivity adjustment of $2,404,135. Both of these are shown at the Utah level.

Q. Are you proposing other adjustments to labor related costs?

A. Yes. I am proposing an adjustment to the Company's projected medical expense.

Q. What did the Company request with respect to future medical costs.

A. The Company's forecasted test year includes $51,061,850 for Medical Plan expenses. This is an increase of $6,519,184 over the annualized June 2007 expenses level of $44,542,675. This represents an increase of 14.6% for the 18-month forecast period, or 9.8% annually. To support its requested increase, the Company cites a significant upward trend in healthcare costs in recent years and references a statement from its consultant, Hewitt Associates, that medical cost rates are anticipated to increase between 8% and 12% in 2008.

Q. Are you aware of other professional consulting firms that provide health care cost information that differs in the forecast of health care cost trends?

[15] See report referenced in SDG&E Application 06-12-010 filed December 8, 2006.

A. Yes. Towers Perrin also provides information concerning health care costs estimates. In its 2008 Health Care Cost Survey, Towers Perrin states that health care cost for U.S. employers will increase by 6% in 2008. The report states that the health care cost estimates for 2008 are the result of employer efforts to aggressively manage benefit program performance. Towers Perrin also indicates that the annual costs per employee for retirees will increase by 6% on average. The Towers Perrin report further states that high performing companies should expect medical cost increases of 5% or less.

Q. What is the Division's forecast of the Company's 2008 medical expense?

A. The Division's forecast for the Company's 2008 Medical Plan costs is $47,924,793. This is an increase of $3,382,118, or 7.6% for the 18 month forecast, or 5.06% annually.

Q. How does this estimate differ from the Company medical cost expense forecast?

A. The Division's forecast differs primarily because it uses the 2008 Towers Perrin estimate of employer cost increases of 5% or less for high performing companies. From a ratemaking perspective, and especially in a situation where a forecasted test year is being used, the Company should be expected to aggressively contain future medical costs. The testimony of Company witness Erich Wilson strongly suggests that the Company has indeed shifted its focus to a more aggressive policy regarding the containment of medical costs.

Q. What is the amount of your proposed adjustment?

A. This adjustment reduces operating expenses by $2,302,071 on a Total Company basis, and by $984,164 at the Utah jurisdictional level.

V. INCENTIVE COMPENSATION

Q. Have you reviewed the level of incentive compensation expense the Company has included in the current rate case?

A. Yes. The Company seeks to include $23,860,892 of incentive compensation expenses on a Total Company basis. The amount included in the Utah revenue requirement is $10,482,905.

Q. What is the breakdown of incentive payments between FLSA exempt and non-exempt employees?

A. The expense portion of budgeted payments to exempt employees is $22,745,049 and the portion budgeted for nonexempt employees is $1,115,843. The Utah amount for exempt employees is approximately $9,992,677 and $490,228 for non-exempt employees. These expense levels are set forth on Table 1 below.

Table 1: Incentive Compensation Expense

Description	Total Company	Utah Jurisdictional
Exempt Employees	$22,745,049	$9,992,677
Non-Exempt Employees	$1,115,843	$490,228
Total Expense	$23,860,892	$10,482,905

Q. How is incentive compensation generally treated for ratemaking purposes?

A: Most jurisdictions limit the amount of incentive compensation to be recovered in rates. When costs associated with incentive compensation plans are excluded from rates, the rationale is generally based on one or more of the following reasons:

(1) **Payment is uncertain.** Generally, payment of incentive compensation is conditioned upon meeting some predetermined goal such as achieving a certain increase in earnings or reaching a targeted stock price. If the predetermined objective is not met, the incentive payment is not made. Therefore, there is no certainty from year to year whether the payment will be made or not. It would be inappropriate to set prospective rates to recover such a tentative expense.

(2) **Incentive plans based on company earnings are held in general disfavor because many factors that significantly impact earnings are outside the control of most company employees and have limited value to customers.[16]** For example, an unusually hot summer may trigger an incentive payment based on company earnings for an electric utility. Obviously, weather conditions are outside the control of utility employees and customers receive no benefit from the higher utility bills that result from the warm weather. Similarly, company earnings may increase as result of customer growth, which commonly occurs without significant influence from company personnel. In fairness, since shareholders enjoy the benefits of customer growth between rate cases, shareholders should also bear the cost of any incentive payments such growth

[16] See, *U.S. West Communications, Inc. v. Public Service Comm'n*, 901 P.2d 270, 276-77 (Utah 1995); *Central Illinois Public Service Company Proposed General Increase In Natural Gas Rates*, Docket No. 02-0798 (Cons.), 2003 Ill. PUC LEXIS 824, p. 115 (Illinois Commerce Comm'n 2003); *Application of Wisconsin Power and Light Company as an Electric, Natural Gas and Water Utility for Authority to Change Electric, Natural Gas, and Water Rates*, Docket No. 6680-UR-113, 2003 Wisc. PUC LEXIS 822, pp. 40-41 (Wisconsin Public Service Comm'n 2003); *Petition of Northern States Power Company's Gas Utility for Authority to Change its Schedule of Gas Rates for Retail Customers Within the State of Minnesota*, 146 P.U.R.4th 1, pp. 40-43 (Minnesota Public Util. Comm'n 1993); *Application of Minnegasco, a Division of NorAm Energy Corp., for Authority to Increase its Natural Gas Rates in Minnesota*, 170 P.U.R.4th 193, pp. 69-77 (Minnesota Public Util. Comm'n 1996).

may trigger. Finally, utility earnings may increase substantially if the utility is able to successfully argue for a higher ROE in a rate case proceeding. However, utility efforts to maximize ROE in a rate proceeding have little to do with improving overall employee performance across the company. If utility employee efforts are geared toward securing *unreasonably* high ROE in rate proceedings, the incentive mechanism actually would work to the detriment of the utility customers.

(3) Earnings-based incentive plans can discourage conservation. When incentive payments are based on earnings, employees may not be as supportive of conservation programs designed to reduce usage if they perceive these programs could adversely impact incentive payment levels. To the extent earnings-based incentive plans discourage conservation and demand-side management programs, these plans would not be in the public interest.

(4) The utility and its stockholders assume none of the financial risks associated with incentive payments. Ratepayers assume the risk that the amounts collected through rates for incentive payments will instead be retained by the utility whenever targeted increases are not reached. Employees assume the risk that the incentive payments will not be made in a given year. However, the utility and its stockholders assume no risk associated with these payments. Instead, the company's only responsibility is to decide who gets the money, the stockholders or the employees.

(5) Incentive payments based on financial performance measures should be made out of increased earnings. Whatever the targets or goals may be that trigger an incentive payment, when the plan is based in whole or in part on financial performance measures there is always a financial benefit to the company that comes from achieving these objectives. That financial benefit always provides ample funds from which to make the payment. If not, the incentive plan was poorly conceived in the first place. As such, employees should be compensated out of the increased earnings, and not through rates.

(6) Incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition. Many understand that utilities seek to embed amounts for incentive payments in operating expense not so the money will be available to pay the incentive payment when financial performance goals are met but rather to supplement earnings in those years when the company does not perform well. In those years when financial performance measures are met, the increased earnings of the company provide ample additional funds from which to make the incentive payments to employees, and the incentive payment amount embedded in rates is not needed. In those years when financial performance measures are not met and the incentive payments are not made, the amount

> embedded in rates for incentive payments acts as a financial hedge to shelter the poor financial performance of the company.

Even though regulators often exclude incentive compensation payments based on one or more of the reasons outlined above, this does not mean that regulated companies should not offer incentive compensation packages. On the contrary, incentive plans that motivate employees to achieve increased efficiencies should be encouraged. However, since the utility retains all of the savings generated from these increased efficiencies between rate cases, payment to the employees for these plans should be made from a portion of the savings these plans help achieve. Thus, properly designed incentive compensation plans need not be subsidized by ratepayers.

Q. What standard does Utah apply in determining the amount of incentive compensation recoverable through rates?

A. Typically, the Commission only allows in rates the portion of a company's incentive compensation plan that is shown to be based on operational goals that provide ratepayer benefits, such as measurable improvements in quality of service, while any portion of the incentive compensation plan that relates to earning and rate of return is generally excluded.[17]

Q. Please describe the Company's incentive compensation plan.

A. The Company provided a copy of its 2007 Annual Incentive Plan. The stated objectives of the plan are as follows:

> PacifiCorp's Annual Incentive Plan provides performance awards based on the following: achieving the goals of PacifiCorp, Pacific Power, Rocky Mountain Power and PacifiCorp Energy; individual performance; company management

[17] GCIS Response, Utah PUC, Commission Utility Economist. See US West Communications Rate Case Docket 95-049-05; Missouri Corp. Rate Case Docket 97-035-01.

> of risk and safety; and success in addressing new issues and opportunities that may arise during the course of the year. Awards will be made based upon measurable achievement of results. Achievement will be measured by senior management. This approach supports the philosophy of incentive compensation as pay at risk that is earned based on the company, business unit and individual performance."[18]

The plan also sets forth following four "Plan Components:"

- Incentive awards are structured to achieve a target incentive payout. Target award percentages are based on job classification derived from competitive market data.

- All participants will have an award opportunity based upon company, business unit and individual performance as measured and assessed by senior management.

- Company and business unit performance will be evaluated based on meeting objectives established in operating and business plans and the organization's success in responding to unexpected events.

- Any additional changes for individual performance will be reviewed by each president (business unit leader) and a final decision made in collaboration with senior management prior to final award determination.

Q. In your opinion does the plan specify any objective measures of performance?

A. No. From the information the Company provided there are no clear identifiable benchmarks of any kind. Incentive compensation payments appear to be based solely on the discretion of senior management and the criteria that senior management will use to measure and assess performance are not sufficiently identified. The Company provided a copy of the 2007 plan year goals for Rocky Mountain Power President, Mr. A. Richard Walje. These stated goals did not outline specific or measurable benchmarks for employee performance, nor did they adequately explain the linkage between the general objectives and the incentives to be paid.

[18] Response to DPU 23.1 b.

Q. In your opinion, are there fundamental problems with the Company's incentive compensation plan that should be corrected before the Commission allows recovery of plan costs?

A. Yes. Before the Commission allows recovery of plan costs, the plan should define objective measures of performance. Each of the various objectives should be given a weighting and a formula so that the incentive value of each objective can be calculated. The plan should provide for a payment methodology that ensures that if the performance objectives and benchmarks are met, the company has a firm obligation to make incentive payments. The plan in its current form lacks specificity and is completely subjective.

Q: Do most jurisdictions require that an incentive plan define objective and quantifiable benefits to customers as important criteria for determining whether that plan is a recoverable expense for ratemaking purposes?

A: Yes. It is important for regulators to be able to assess the actual goals and incentives that cause the incentive payments to be triggered. Many jurisdictions focus on quantifiable goals such as measurable increases in reliability and quality of service to the customers. On the other hand, where the overriding goal of the incentive plan is to increase shareholder earnings, the incentive compensation should be funded out of the increased earnings that trigger the payments.

Q: Can you provide some examples of the methodology other jurisdictions apply in evaluating incentive compensation plans?

A: Yes. In April of 2007, the Garrett Group, LLC conducted a survey of utility commissions in the western United States regarding the rate treatment of incentive compensation. That survey showed that most states follow guidelines similar to those outlined above to evaluate the portion of utility incentive compensation plans allowed in rates. Some states disallow incentive pay using other criteria, and a few states have no established policy with respect to incentive compensation. However, none of the jurisdictions surveyed allow full recovery of incentive compensation through rates as a general rule.

> Oklahoma: Oklahoma follows the general rule that costs tied to financial performance measures are disallowed, while costs associated with customer satisfaction and reliability may be included. Under this approach, executive incentive compensation is generally disallowed altogether.[19]

> Washington: The portion of the expense tied to efficiency increases is allowed while the part that results from increasing the bottom line is disallowed.[20]

> Oregon: Oregon's general policy is to disallow 100% of officer bonuses. The portion of employee incentives plans based on customer service is allowed and the portion based on increased returns is disallowed.[21]

> Idaho: As general policy, Idaho does not allow the costs of plans associated with profits and earnings performance, but does allow the costs associated with improved customer service. Executive's incentive compensation plans are evaluated using the same criteria and are not often allowed.[22]

> Texas: The general policy in Texas is to allow the portion of the plan based on rate payer benefits, such as quality of service and to exclude the portion that relates to earnings and rate of return.[23]

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[19] In Cause No. PUD 91-1190, the Oklahoma Commission disallowed 100% of Oklahoma Natural Gas Company's ("ONG") employee incentive plans, based upon the arguments of Staff and the Attorney General that the plans were designed to increase corporate earnings and that payments were uncertain from year to year. In Cause No. PUD 200400610, the Oklahoma Commission again disallowed 100% of ONG's incentive plans, stating that "a well designed incentive compensation plan will generate resources from which to pay the incentives." In Cause No. PUD 200500151, Oklahoma Gas and Electric's ("OG&E") last general rate case, the Oklahoma Commission disallowed 60% of OG&E's employee incentive plans. In Cause No. PUD 200600285, the Oklahoma Commission disallowed 50% of AEP-PSO's Annual incentive Plans and 100% of the Executive Stock Plan.
[20] Garrett Group, LLC, Incentive Compensation Survey, conducted April 2007, ("GICS"), Response of Washington UTC; See Order in Docket 061546, Pacific Power and Light.
[21] GICS Response, Oregon PUC, Manager of Rates and Tariffs.
[22] GICS Response, Idaho PUC, Accounting Section Supervisor. See Idaho Power Company Rate Case IPC-E-05-28; Idaho Power Company IPC-05-28.
[23] See PUC Docket No. 28840.

N. Dakota: The general policy in North Dakota is to exclude that portion that relates to shareholder earnings. The rest is included.[24]

S. Dakota: The approach used in South Dakota is incentive payments triggered by shareholder returns are disallowed.[25]

Missouri: Missouri includes only the portion that benefits consumers, and otherwise disallows incentive compensation. The same criteria are used for executive plans. Most of the costs of executive plans are excluded.[26]

Kansas: Staff opposes plans without objective measures of ratepayer benefits.[27]

New Mexico Staff included 20% of PSNM's incentive pay because 20% was tied to achieving customer satisfaction and operating efficiency goals. Staff excluded the 80% tied to achieving corporate financial goals and earnings per share targets.[28]

Utah The Commission allows the portion of incentive compensation shown to be based on operational goals that provide ratepayer benefits, such as measurable improvements in quality of service, while any portion of the incentive compensation plan that relates to earning and rate of return is generally excluded.[29]

<u>States that Exclude Incentive Costs Using Other Criteria</u>

Arizona: Arizona generally does not allow the costs for these programs in rates, but they have at times allowed 50% of the cost of a particularly good plan.[30]

Colorado: The Office of Consumer Council argued for removing the costs of the plan not benefiting ratepayers. That case settled. In the current gas utility rate case staff is removing incentive compensation from rates.[31]

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[24] GICS Response, Director of Accounting, North Dakota PSCC

[25] GICS Response, South Dakota PSC.

[26] GICS Response, Missouri PSC, Utility Services Division. See recent Kansas City Power and Light and Empire Electric District orders on the Commission's website.

[27] GICS Response, Kansas Corporation Commission, Utilities Division.

[28] GICS Response, New Mexico Public Regulation Commission, Accounting Bureau, See Staff testimony in Public Service Co., of New Mexico, Case No. 06-00210-UT.

[29] GICS Response, Utah PUC, Commission Utility Economist. See US West Communications Rate Case Docket 95-049-05; Missouri Corp. Rate Case Docket 97-035-01.

[30] GICS Response, Arizona Corporation Commission.

[31] GICS Response, Colorado PUC, See Docket 06-S-234-EG.

Minnesota: After the 1991 decision to deny earnings per share incentive costs, the Commission began to allow the costs of some plans, but capped recovery at a low percentage of base salary out of a concern that larger percentages tie employees too closely to shareholders' interests. The portion that is allowed in rates is tracked and returned to ratepayers if not paid to employees. The cost of executive incentives is generally excluded.[32]

Q. The Company maintains that its incentive plan is focused on operational goals instead of financial goals. Do you agree?

A. The Company provided only the goals for the President of Rocky Mountain Power. While it appears some of these goals relate to operational measures that benefit customers, there are no stated benchmarks or objective measures provided in the plan, and no linkage between the attainment of specific results and the payments of incentives. Thus, it is impossible to determine how these stated goals translate into incentive compensation awards to the employees. The subjective nature of the plan is such that the Company has not actually obligated itself to make any incentive payments based on achieving specific identifiable operational goals that provide measurable benefits to ratepayers.

Q. Are there other indications that the Company's incentive awards are more likely tied to financial rather than customer-related goals?

A. Yes. Of the Company's test year incentive payments, exempt employees received $22,745,049 while nonexempt employees received only $1,115,843. This means that more than 95% of the incentive award went to management and executive level employees whose interests are typically more aligned with the interests of shareholders. Management and executive employees are also generally in a better position to impact the financial condition

[32] GCIS Response, Minnesota PUC. See General Rate Case E002/GR/05/1428, September 1, 2006.

of the company. The employees closest to the customers, and best able to have a direct impact on customer service and reliability, the nonexempt employees, received less than 5% of the incentive awards.

Q. What is your recommendation to the Commission regarding incentive compensation expenses?

A. Since there has been no demonstration by the Company that any portion of the incentive compensation is tied solely to the achievement of specific, quantifiable customer-specific goals, I recommend that the Commission allow the Company to recover the budgeted expenses for the non-exempt employees, and disallow recovery of the portion attributable to exempt employees. Due to the highly subjective and discretionary nature of the plan, I believe that incentive payments from year to year are, in reality, tied to the financial performance of the Company. As such, these costs should not be included in rates. If the Company can demonstrate in rebuttal testimony a clear delineation of customer-specific goals and demonstrate the amount of incentive the Company is obligated to pay if these goals are achieved, I would be willing to revisit my recommendation on this issue.

Q. What is the amount of the adjustment you are recommending?

A. I recommend that the Utah jurisdictional revenue requirement be reduced by $9,992,677. On a Total Company basis the adjustment is $22,745,049.

VI. POWERDALE ADJUSTMENT

Q. Have you reviewed the testimony and Commission orders regarding the Powerdale Plant decommissioning?

A. Yes. The Powerdale Plant was damaged by flood and debris flow on the Hood River in November, 2007. The Company proposed the early retirement of the Powerdale Plant, stating that it would cost more to repair and operate the facility until its scheduled decommissioning in 2010 than it would to retire the plant now. The Company filed an application requesting an order permitting the transfer of the undepreciated plant balance to other accounts and the creation of a regulatory asset for the estimated decommissioning expenses. On January 3, 2008 the Commission issued an order granting the request for an accounting order, subject to future review and adjustment. The Commission set a tentative three year amortization period beginning January 1, 2007[33].

Q. What did the Company include in the current rate application related to the Powerdale Plant?

A. The Company filed its application in this case before the Powerdale accounting order was issued. In this docket, the Company requested recovery of the decommissioning costs over a period of 5.43 years, and amortization of the undepreciated plant balance over 6.88 years. The decommissioning expenses are estimated at $6.3 million and the undepreciated plant balance is $8.9 million. The Company requested an annual amortization of $1,211,786 for the decommissioning costs and $1,248,204 for the undepreciated plant balances on a Total Company basis.

Q. What is the normal regulatory accounting treatment for retired assets?

A. When an asset is retired, any remaining plant balance is debited to accumulated depreciation along with removal costs, less salvage proceeds. If the plant is either under or over-

[33] Report and Order, Docket No. 07-035-14, dated January 3, 2008.

depreciated the difference is either recovered, or returned, as the case may be, over the remaining useful life of the other assets in the asset group. In other words, the over or under-recovery of depreciable plant is addressed prospectively over the remaining lives of the remaining plant in service.

Q. Do you recommend any changes to the Company's requested recoveries of decommissioning costs or the un-recovered Powerdale Plant balance?

A. No. The Company's requested recovery periods do not seem unreasonably short. However, the Division reserves the right to address this issue further after reviewing the testimony filed by other parties.

VII. CONCLUSION AND RECOMMENDATION

Q. Please summarize your recommendations in this case?

A. I am proposing the following five adjustments:

	Description	**Total**	**Utah**
1	Remove CWC Allowance	$61,631,670	$31,688,954
2	Adjust Base Year Pay Raise Impact	$ 3,269,182	$ 1,397,616
3	Adjust Test Period for Productivity Growth	$ 5,623,544	$ 2,404,135
4	Adjust Medical Cost Increase	$ 2,302,071	$ 984,164
5	Remove Incentive Compensation Pay	$22,745,049	$ 9,992,677
6	Total Rate Base Adjustments	$61,631,670	$31,688,954
7	Total Operating Expense Adjustments	$33,939,846	$14,778,592

Q. Does this conclude your testimony at this time?

A. Yes.

Attachment 1

QUALIFICATIONS OF MARK E. GARRETT

EDUCATION:

Juris Doctor Degree, Cum Laude, Oklahoma City University Law School, 1997
Post Graduate Hours in Accounting, Finance and Economics, 1984-85:
University of Texas at Arlington
University of Texas at Pan American
Stephen F. Austin State University
Bachelor of Arts Degree, University of Oklahoma, 1978

CREDENTIALS:

Member Oklahoma Bar Association, 1997, License No. 017629
Certified Public Accountant in Oklahoma, 1992, Certificate No. 11707-R
Certified Public Accountant in Texas, 1986, Certificate No. 48514

WORK HISTORY:

CONSULTING PRACTICE (1995 - Present) Participate as a consultant and expert witness in electric utility, natural gas distribution company, and natural gas pipeline matters before regulatory agencies making recommendations related to cost-based rates. Review management decisions of regulated utility companies for reasonableness from a ratemaking perspective, especially in proceedings to review the reasonableness of prices paid for natural gas supplies, natural gas transportation, coal supplies, coal transportation and purchased power. Participate in gas gathering, gas transportation, gas contract and royalty valuation disputes to determine pricing and damage calculations and to make recommendations concerning the reasonableness of charges to royalty and working interest owners and other interested parties. Participate in regulatory proceedings to restructure the electric and natural gas utility industries.

OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial Analysis (1991 - 1995) Planned and supervised the audits of major public utility companies doing business Oklahoma for the purpose of determining revenue requirements. Presented both oral and written testimony as an expert witness for Staff in defense of numerous accounting and financial recommendations related to cost-of-service based rates. Audit work and testimony covered all areas of rate base and operating expense. Supervised, trained and reviewed the audit work of numerous Staff CPAs and auditors. Promoted from Supervisor of Audits to Coordinator in 1992.

FREEDOM FINANCIAL CORPORATION - Controller for Real Estate Development Company with $300 million in assets (1987 - 1990) Responsible for all financial reporting including monthly and annual financial statements, cash flow statements, budget reports, long-term financial planning, tax planning and personnel development. Managed the General Ledger and Accounts Payable departments and supervised a staff of seven CPAs and accountants. Reviewed all subsidiary state and federal tax returns and facilitated the annual independent financial audit and all state or federal tax audits. Received promotion from Assistant Controller in September 1988.

SHELBY, RUCKSDASHEL & JONES, CPA's - Auditor (1985 - 1987) audited the financial statements of businesses in the State of Texas, with an emphasis in financial institutions.

<u>**Previous Experience Related to Cost-of-Service, Rate Design, Pricing and Energy-Related Issues**</u>

1. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334) –** Participating as an expert witness in EGSI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

2. **Public Service Company of Oklahoma, 2008 (Cause No. 07-465) –** Participated as an expert witness on behalf of the Oklahoma Industrial Energy Consumers ("OIEC") before the OCC in PSO's application to recover the pre-construction costs of the cancelled Red Rock coal generation facility.

3. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447) –** Participating as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization to recover the pre-construction costs of the cancelled Red Rock coal generation facility using proceeds from sales of excess SO_2 allowances.

4. **Rocky Mountain Power, 2008 (Docket No. 07-035-93) –** Participating as an expert witness on behalf of Staff in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

5. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-449) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

6. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-397) –** Participated as an expert witness on behalf of OIEC before the OCC in PSO's application seeking authorization to defer storm damage costs in a regulatory asset account and to recover the costs using the proceeds from sales of excess SO_2 allowances.

7. **Oklahoma Gas & Electric Co., 2007 (Cause No. PUD 07-012) –** Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application seeking pre-approval to construct the Red Rock coal plant to address the Company's proposed rider recovery mechanism.

8. **Oklahoma Natural Gas Co., 2007 (Cause No. PUD 07-335) –** Participated as an expert witness on behalf of the OIEC before the OCC in ONG's application proposing alternative cost recovery for the Company's ongoing capital expenditures through the proposed Capital Investment Mechanism Rider ("CIM Rider"). Sponsored testimony to address ONG's proposal.

9. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030) –** Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking a used and useful determination for its planned addition of the Red Rock coal plant to address the Company's use of debt equivalency in the competitive bidding process for new resources.

10. **Public Service Company of Oklahoma, 2006 (Cause No. PUD 06-285) –** Participating as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

11. **Nevada Power Company, 2007, (Docket No. 07-01022) -** Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

12. **Nevada Power Company, 2006, (Docket No. 06-11022) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

13. **Southwestern Public Service Co., 2006 (PUCT Docket No. 37766) –** Participated as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application. Provided testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsored the Accounting Exhibits on behalf of AXM.

14. **Atmos Energy Corp., Mid-Tex Division, 2006 (Texas GUD 9676) –** Participated as an expert witness in the Atmos Mid-Tex general rate case application on behalf of the Atmos Texas Municipalities "ATM"). Provided written and oral testimony before the Railroad Commission of Texas regarding the revenue requirements of Mid-Tex including various rate base, operating expense, depreciation and tax issues. Sponsored the Accounting Exhibits for ATM.

15. **Nevada Power Company, 2006 (Docket No. 06-06007) –** Participated as an expert witness on behalf of the MGM MIRAGE in the Sinatra Substation Electric Line Extension and Service Contract case. Provided both written and oral testimony before the Nevada Public Utility Commission to provide the Commission with information as to why the application is consistent with the line extension requirements of Rule 9 and why the cost recovery proposals set forth in the application provide a least cost approach to adding necessary new capacity in the Las Vegas strip area.

16. **Public Service Co. of Oklahoma, 2006 (Cause No. PUD 05-00516) -** Participated as an expert witness on behalf of the OIEC to review PSO's application for a "used and useful" determination of its proposed peaking facility.

17. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 06-00041) –** Participated as an expert witness on behalf of the OIEC in OG&E's application to propose an incentive sharing mechanism for SO_2 allowance proceeds.

18. **Chermac Energy Corporation, 2006 (Cause No. PUD 05-00059 and 05-00177) –** Participated as an expert witness on behalf of the OIEC in Chermac's PURPA application. Sponsored written responsive and rebuttal testimony to address various rate design issues arising under the application.

19. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 05-00140) –** Participated as an expert witness on behalf of the OIEC in OG&E's 2003 an 2004 Fuel Clause reviews. Sponsored written testimony to address the purchasing practices of the Company, it transactions with affiliates, and the prices paid for natural gas, coal and purchased power.

20. **Nevada Power Company, 2006, (Docket No. 06-01016) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written testimony in NPC's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

21. **Oklahoma Gas and Electric Co., 2005 (Cause No. PUD 05-151) –** Participated as an expert witness on behalf of the OIEC in OG&E's general rate case application. Sponsored both written and oral testimony before the OCC to address various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates.

22. **Oklahoma Natural Gas Co., 2005 (Cause No. PUD 04-610) –** Participated as an expert witness on behalf of the Attorney General of Oklahoma. Sponsored written and oral testimony to address numerous rate base, operating expense and depreciation issues for the purpose of setting prospective cost-of-service based rates.

23. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187)** – Participating as an expert witness on behalf of the Attorney General of Oklahoma: Sponsored written testimony to provide the OCC with analysis from an accounting and ratemaking perspective of the Co.'s proposed change in depreciation rates from an Average Life Group to an Equal Life Group methodology. Addressed the Co.'s proposed increase in depreciation rates associated with increased negative salvage value calculations.

24. **Public Service Co. of Oklahoma, 2004 (Cause No. PUD 02-0754) –** Participated as an expert witness on behalf of the OIEC. Sponsored written testimony (1) making adjustments to PSO's requested recovery of an ICR programming error, (2) correcting errors in the allocation of trading margins on off-system sales of electricity from AEP East to West and among the AEP West utilities and (3) recommending an annual rather than a quarterly change in the FAC rates.

25. **PowerSmith Cogeneration Project, 2004 (Cause No. PUD 03-0564) -** Participated as an expert witness on behalf of the OIEC to provide the OCC with direction in setting an avoided cost for the PowerSmith Cogeneration project under PURPA requirements. Provided both written and oral testimony on the provisions of the proposed contract under PURPA:

26. **Electric Utility Rules for Affiliate Transactions, 2004 (Cause No. RM 03-0003)** – Participated as a consultant on behalf of the OIEC to draft comments to assist the OCC in developing rules for affiliate transactions. Assisted in drafting the proposed rules. Successful in having the Lower of Cost or Market rule adopted for affiliate transactions in Oklahoma.

27. **Nevada Power Company, 2003, (Docket No. 03-10001) -** Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

28. **Nevada Power Company, 2003, (Docket No. 03-11019) -** Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

29. **Oklahoma Gas & Electric Co., 2003 –** Participated as an expert witness on behalf of the OIEC in OG&E's general rate case application before the OCC to address numerous rate base, operating expense and rate design issues for the purpose of setting prospective cost-of-service based rates.

30. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076) –** Participating as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

31. **Oklahoma Gas & Electric Co., 2003 (Cause No. PUD 03-0226) –** Participated as an expert witness on behalf of the OIEC. Provided both written and oral testimony before the OCC to determine the appropriate level to include in rates for natural gas transportation and storage services acquired from an affiliated company.

32. **Nevada Power Company, 2003 (Docket No. 02-5003-5007) -** Participated as an expert witness on

behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony to calculate the appropriate exit fee in MGM Mirage's 661 Application to leave the system.

33. **McCarthy Family Farms, 2003 –** Participated as a consultant to assist in converting a biomass and biosolids composting process into a renewable energy power producing business in California.

34. **Bice v. Petro Hunt, 2003 (ND, Supreme Court No. 20030306) -** Participated as an expert witness in a class certification proceeding to provide cost-of-service calculations for royalty valuation deductions for natural gas gathering, dehydration, compression, treatment and processing fees in North Dakota.

35. **Nevada Power Company, 2003 (Docket No. 03-11019) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power. Provided written and oral testimony on the reasonableness of the cost allocations to the utility's various customer classes.

36. **Wind River Reservation, 2003 (Fed. Claims Ct. No. 458-79L, 459-79L) –** Participated as a consulting expert on behalf of the Shoshone and Arapaho Tribes to provide cost-of-service calculations for royalty valuation deductions for gathering, dehydration, treatment and compression of natural gas and the reasonableness of deductions for gas transportation.

37. **Oklahoma Gas & Electric Co., 2002 (Cause No. PUD 01-0455) –** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored written and oral testimony on numerous revenue requirement issues including rate base, operating expense and rate design issues to establish prospective cost-of-service based rates.

38. **Nevada Power Company, 2002 (Docket No. 02-11021) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power and to make recommendations with respect to rate design.

39. **Nevada Power Company, 2002 (Docket No. 01-11029) -** Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power included in the Company's $928 million deferred energy balances.

40. **Nevada Power Company, 2002 (Docket No. 01-10001) -** Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

41. **Chesapeake v. Kinder Morgan, 2001 (CIV-00-397L) -** Participated as an expert witness on behalf of Chesapeake Energy in a gas gathering dispute. Sponsored testimony to calculate and support a reasonable rate on the gas gathering system. Performed necessary calculations to determine appropriate levels of operating expense, depreciation and cost of capital to include in a reasonable gathering charge and developed an appropriate rate design to recover these costs.

42. **Southern Union Gas Company, 2001 -** Participated as a consultant to the City of El Paso in its review of SUG's gas purchasing practices, gas storage position, and potential use of financial hedging instruments and ratemaking incentives to devise strategies to help shelter customers from the risk of

high commodity price spikes during the winter months.

43. **Nevada Power Company, 2001 -** Participated as an expert witness on behalf of the MGM-Mirage, Park Place and Mandalay Bay Group before the Nevada Public Utility Commission to review NPC's Comprehensive Energy Plan (CEP) for the State of Nevada and make recommendations regarding the appropriate level of additional costs to include in rates for the Company's prospective power costs associated with natural gas and gas transportation, coal and coal transportation and purchased power.

44. **Bridenstine v. Kaiser-Francis Oil Co. et al., 2001 (CJ-95-54) -** Participated as an expert witness on behalf of royalty owner plaintiffs in a valuation dispute regarding gathering, dehydration, metering, compression, and marketing costs. Provided cost-of-service calculations to determine the reasonableness of the gathering rate charged to the royalty interest. Also provided calculations as to the average price available in the field based upon a study of royalty payments received on other wells in the area.

45. **Klatt v. Hunt et al., 2000 (ND) -** Participated as an expert witness and filed report in United States District Court for the District of North Dakota in a natural gas gathering contract dispute to calculate charges and allocations for processing, sour gas compression, treatment, overhead, depreciation expense, use of residue gas, purchase price allocations, and risk capital.

46. **Oklahoma Gas and Electric Co., 2000 (Cause No. PUD 00-0020) -** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Generation Efficiency Performance Rider (GEPR). Provided a list of criteria with which to measure a utility's proposal for alternative ratemaking. Recommended modifications to the Company's proposed GEPR to bring it within the boundaries of an acceptable alternative ratemaking formula.

47. **Oklahoma Gas and Electric Co., 1999 -** Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Performance Based Ratemaking (PBR) proposal including analysis of the Company's regulated return on equity, fluctuations in the capital investment and operating expense accounts of the Company and the impact that various rate base, operating expense and cost of capital adjustments would have on the Company's proposal.

48. **Nevada Power Company, 1999 (Docket No. 99-7035) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony addressing the appropriate ratemaking treatment of the Company's deferred energy balances, prospective power costs for natural gas, coal and purchased power and deferred capacity payments for purchased power.

49. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to unbundle the utility services of the NPC and to establish the appropriate cost-of-service allocations and rate design for the utility in Nevada's new competitive electric utility industry.

50. **Nevada Power Company, 1999 (Docket No. 99-4005) -** Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to establish the cost-of-service revenue requirement of the Company.

51. **Nevada Power/Sierra Pacific Merger, 1998 (Docket No. 98-7023) -** Participated as an expert witness on behalf of the Mirage and MGM Grand before the Nevada PUC. Sponsored written and oral testimony to establish (1) appropriate conditions on the merger (2) the proper sequence of

regulatory events to unbundle utility services and deregulate the electric utility industry in Nevada (3) the proper accounting treatment of the acquisition premium and the gain on divestiture of generation assets. The recommendations regarding conditions on the merger, the sequence of regulatory events to unbundle and deregulate, and the accounting treatment of the acquisition premium were specifically adopted in the Commission's final order.

52. **Oklahoma Natural Gas Company, 1998 (Cause No. PUD 98-0177) -** Participated as an expert witness in ONG's unbundling proceedings before the OCC. Sponsored written and oral testimony on behalf of Transok, LLC to establish the cost of ONG's unbundled upstream gas services. Substantially all of the cost-of-service recommendations to unbundle ONG's gas services were adopted in the Commission's interim order.

53. **Public Service Company of Oklahoma, 1997 (Cause No. PUD 96-0214) -** Audited both rate base investment and operating revenue and expense to determine the Company's revenue requirement and cost-of-service. Sponsored written testimony before the OCC on behalf of the OIEC.

54. **Oklahoma Natural Gas /Western Resources Merger, 1997 (Cause No. PUD 97-0106) -** Sponsored testimony on behalf of the OIEC regarding the appropriate accounting treatment of acquisition premiums resulting from the purchase of regulated assets.

55. **Oklahoma Gas and Electric Co., 1996 (Cause No. PUD 96-0116) -** Audited both rate base investment and operating income. Sponsored testimony on behalf of the OIEC for the purpose of determining the Company's revenue requirement and cost-of-service allocations.

56. **Oklahoma Corporation Commission, 1996 -** Provided technical assistance to Commissioner Anthony's office in analyzing gas contracts and related legal proceedings involving ONG and certain of its gas supply contracts. Assignment included comparison of pricing terms of subject gas contracts to portfolio of gas contracts and other data obtained through annual fuel audits analyzing ONG's gas purchasing practices.

57. **Tenkiller Water Company, 1996 -** Provided technical assistance to the Attorney General of Oklahoma in his review of the Company's regulated cost-of-service for the purpose of setting prospective utility rates.

58. **Arkansas Oklahoma Gas Company, 1995 (Cause No. PUD 95-0134) -** Sponsored written and oral testimony before the OCC on behalf of the Attorney General of Oklahoma regarding the price of natural gas on AOG's system and the impact of AOG's proposed cost of gas allocations and gas transportation rates and tariffs on AOG's various customer classes.

59. **Enogex, Inc., 1995 (FERC 95-10-000) -** Analyzed Enogex's application before the FERC to increase gas transportation rates for third party shippers and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.

60. **Oklahoma Natural Gas Company, 1995 (Cause No. PUD 94-0477) -** Analyzed a portfolio of ONG's gas purchase contracts in the Company's Payment-In-Kind (PIC) gas purchase program and made recommendations to the OCC Staff on behalf of Terra Nitrogen, Inc. regarding the inappropriate profits made by ONG on the sale of the gas commodity through the PIC program pricing formula. Also analyzed the price of gas on ONG's system, ONG's cost-of-service based rates, and certain class cross-subsidizations in ONG's existing rate design.

61. **Arkansas Louisiana Gas Company, 1994 (Cause No. PUD 94-0354) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of the other auditors on the case. Sponsored cost-of-service testimony on cash working capital and developed policy recommendations on post test year adjustments.

62. **Empire District Electric Company, 1994 (Cause No. PUD 94-0343) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of other auditors. Sponsored cost-of-service testimony on rate base investment areas including cash working capital.

63. **Oklahoma Natural Gas Company, 1992 through 1993 (Cause No. PUD 92-1190) -** Planned and supervised the rate case audit of ONG for the OCC Staff. Reviewed all workpapers and testimony of the other auditors on the case. Sponsored written and oral testimony on numerous cost-of-service adjustments. Analyzed ONG's gas supply contracts under the Company's PIC program.

64. **Oklahoma Gas and Electric Company, 1991 through 1992 (Cause No. PUD 91-1055) -** Audited the rate base, operating revenue and operating expense accounts of OG&E on behalf of the OCC Staff. Sponsored written and oral testimony on numerous revenue requirement adjustments to establish the appropriate level of costs to include for the purpose of setting prospective rates.