Witness CCS – 3
CCS Exhibit – 3

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	**Docket No. 04-035-42**
In the Matter of the Application	)	
Of PacifiCorp for Approval of	)	**PRE-FILED DIRECT TESTIMONY OF**
Its Proposed Electric Service	)	**KIMBERLY H. DISMUKES**
Schedules and Electric	)	**FOR THE COMMITTEE OF**
Service Regulations	)	**CONSUMER SERVICES**

3 December 2004

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. Kimberly H. Dismukes, 6455 Overton Street, Baton Rouge, Louisiana 70808. I am a partner in the firm of Acadian Consulting Group, which specializes in the field of public utility regulation and economic research and analysis. I have been retained by the Utah Committee of Consumer Services (Committee) to analyze portions of PacifiCorp's (the Company) request for a rate increase.

Q. DO YOU HAVE AN APPENDIX THAT DESCRIBES YOUR QUALIFICATIONS IN REGULATION?

A. Yes. Appendix I, attached to my testimony, was prepared for this purpose.

Q. DO YOU HAVE AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes. Exhibits CCS 3.1 through 3.13 support my testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into eight sections. The first section of my testimony is this brief introduction. In the second section I present an overview of the Company's affiliate transactions. This includes the transactions between PacifiCorp and its affiliates but does not include an analysis of the ScottishPower "cross charges." The ScottishPower affiliate charges are being handled by Committee witness Michael Arndt. In the third section of my testimony I address the management fee charged by PacifiCorp to its various affiliates and the allocation methodology employed by the Company. In the fourth section of my testimony I recommend an adjustment to normalize the test year management fees. In the fifth section of my testimony, I discuss the Company's adjustment to reduce rate base by the settlement funds received by PacifiCorp Environmental Remediation Company (PERCO). In the sixth section I discuss the costs included in the test year associated with the West Valley lease arrangement and propose an adjustment. In the seventh section of my testimony I address the Company's treatment of the Bridger Coal Company and propose related adjustments. Finally, in the eighth section of my testimony I discuss the need for PacifiCorp to develop an affiliate transaction/cost allocation manual.

II. OVERVIEW OF AFFILIATE TRANSACTIONS

Q. WHY IS IT IMPORTANT TO CLOSELY EXAMINE AFFILIATE TRANSACTIONS?

A. In a situation involving the provision of services between affiliated companies, the associated transactions and costs do not represent arms-length dealings. Cost allocation techniques and methods of charging affiliates should be frequently reviewed to ensure that the company=s regulated operations are not subsidizing the non-regulated operations. Because of the relationship between PacifiCorp and the affiliates that contribute to expenses included on the books of PacifiCorp, the arms-length bargaining of a normal competitive environment is not present in their transactions. Although each of the affiliated companies is supposedly separate, relationships between PacifiCorp and these affiliates are still close; they all belong to one corporate family.

In the absence of regulation, there is no assurance that affiliate transactions and allocations will not translate into unreasonably high charges for PacifiCorp=s customers. Even when the methodologies for cost allocation and pricing have been explicitly stated, close scrutiny of affiliate relationships is still warranted. Regardless of whether or not PacifiCorp explicitly establishes a methodology for the allocation and distribution of affiliate costs, there is an incentive to misallocate or shift costs to regulated companies so that the unregulated companies can reap the benefits.

Q. DOES THIS COMMISSION HAVE RULES OR POLICIES THAT DIRECT HOW COSTS TO AND FROM AFFILIATES SHOULD BE HANDLED?

A. The Commission does not have explicit rules or policies that govern how costs charged between affiliates should be handled. However, the Commission has in past orders indicated that prices charged to affiliates from the regulated operations of PacifiCorp should be at the higher of cost or market. In Docket No. 99-035-10 the Commission found:

> PacifiCorp often includes messages about its unregulated activities and advertisements promoting sale of unregulated goods and services along with the bills it mails monthly to electric service customers. The messages and advertisements are either separate sheets (called "bill stuffers") or part of the regulated Company's newsletter, "Voices." Though included in the same envelope as the monthly electric service bill, required postage is not increased. The Division proposes to share postage cost

> between the Company's regulated and unregulated activities. The Company opposes the adjustment.
>
> In support of its adjustment, the Division relies on "Guidelines for Cost Allocations and Affiliate Transactions" advocated by the National Association of Regulatory Utility Commissioners (NARUC Guidelines) for authoritative suggestions on how to correct a subsidy flowing from regulated to unregulated Company activities. A good or service provided by the regulated utility to an unregulated affiliate should be priced at the higher of fully distributed, embedded cost or an appropriate price prevailing in the marketplace, states the Division, following the Guidelines.
>
> We begin by observing that the NARUC Guidelines have not been adopted in this jurisdiction. … Be this as it may, this Commission has employed "asymmetric pricing" in previous cases. This is the Guidelines' preferred regulatory approach to affiliate transactions. The higher-of-cost-or-market guideline proposed by the Division is an example of asymmetric pricing. We are prepared to follow this pricing prescription again here, if the facts call for it.
>
> The NARUC Guidelines posit a sensible definition of subsidization, to wit: "the recovery of costs from one class of customers or business unit that are attributable to another**."** No party, including the Company, disputes the fact that unregulated activities receive value, for which they pay nothing, from the mailing of messages and materials along with the customer's bill. Absent a close relationship with the regulated utility, this mailing would not be free. We find there is a subsidy and therefore the higher-of-cost-or-market guideline applies.

While the Commission has not adopted formal rules or policies concerning the charges from affiliates, in the above Order the Commission found that the appropriate guideline is that charges from the regulated operations to unregulated affiliates should be priced at the higher of cost or market. In the context of asymmetric pricing, the charges from an unregulated affiliate to the regulated company should then be priced at the lower of cost or market.

Q. WOULD YOU PLEASE DESCRIBE PACIFICORP'S ORGANIZATIONAL STRUCTURE?

A. Yes. PacifiCorp is a large, complex, and diverse organization, consisting of numerous affiliates that are engaged in regulated and nonregulated activities. CCS Exhibit 3.1 contains an organizational chart depicting the numerous affiliates of the Company.

The primary affiliates are listed below, with a description of the services each provides. Subsidiaries under PacifiCorp are also listed.

- $ ScottishPower plc: The parent company of PacifiCorp and Pacific Group Holdings.
    - Pacific Holdings, Inc. (PHI): PHI is a holding company for four direct subsidiaries: Pacific Klamath Energy, Inc., PacifiCorp Group Holdings Company, PacifiCorp, and PPM Energy, Inc. PHI is a direct parent of PacifiCorp.
        - PacifiCorp: A diversified energy company operating in the United States. It conducts retail electric utility business in six western states. PacifiCorp is a direct subsidiary of PHI and an indirect subsidiary of ScottishPower plc.
            - o Centralia Mining Company
            - o Energy West Mining Company
            - o Glenrock Coal Company
            - o Interwest Mining Company
            - o Pacific Minerals, Inc. (Owns Bridger Coal Company)
            - o PacifiCorp Environmental Remediation Company (PERCO)
            - o PacifiCorp Future Generations, Inc.
            - o PacifiCorp Investment Management, Inc.
        - Pacific Klamath Energy, Inc. (PKE): PKE, in contract with the city of Klamath Falls, Oregon will maintain the recently completed 500 MW cogeneration plant thirty miles from the California-Oregon border.

- Pacific Group Holdings Company (PGH): PGH facilitates the businesses not regulated as electric utilities.
- PPM Energy, Inc. (PPM): PPM is a wholesale power trading company. PPM focuses on wind power, natural gas storage and hub services and gas-fired generation. PPM is a growing nonregulated subsidiary of PHI.

Q. ARE COSTS SHARED AMONG THE VARIOUS AFFILIATES OF PACIFICORP?

A. Yes. CCS Exhibit 3.2 sets forth the costs charged by PacifiCorp to its affiliates and costs charged to PacifiCorp by its affiliates for the years 2001 to 2004 as reported in the Company's 2001 through 2004 Affiliated Interest Reports. As shown on this exhibit, the majority of the costs are charged from PacifiCorp to its affiliates, with the exception of the mining companies which charge the Company a considerable amount. For example, as shown on page 1 of the exhibit, in 2004, PacifiCorp charged PacifiCorp Group Holdings Company $283,466 whereas PacifiCorp Group Holdings Company did not charge the Company anything. Similarly, as shown on page 2 of the exhibit, in 2004, the Company charged PPM $11,421,097, however, PPM only charged the Company $83. As shown on page 13 of this exhibit, charges from PacifiCorp to its affiliates were $2.7 million in 2001, $8.8 million in 2002, $12.3 million in 2003, and $14.1 million in 2004. Charges from affiliates to PacifiCorp were $144.4 million in 2001, $142.4 million in 2002, $143.1 million in 2003, and $154.8 million in 2004. The amounts charged to the Company from affiliates are largely driven by coal purchases and the West Valley lease.

Q. HOW ARE COSTS FROM PACIFICORP CHARGED TO ITS AFFILIATES?

A. Although the Company has no cost allocation manuals which set forth the methods used to charge affiliates for services rendered, it was possible through discovery and discussions with Company personnel to determine what methods were used to charge costs to PacifiCorp's affiliates. PacifiCorp has three methods by which it charges its affiliates for services rendered. These include direct assignments, Corporate Business Services (CBS) Assessments, and the allocation of common costs using a three-factor allocation methodology.

Under the direct assignment approach, invoices specifically related to an activity for an affiliated company are directly charged to that company. Labor to support an affiliate is charged at a fully loaded activity rate to that company. According to the Company, "[l]abor is charged at PacifiCorp's fully loaded cost plus administrative and general expense." (2004 Affiliated Interest Report.) For example, when an employee is assigned to an affiliate project or performs work for an affiliate, these costs are directly assigned/charged to that affiliate.

Under Corporate Business Services Assessments, PacifiCorp utilizes a shared services model for providing Information Technology, Real Estate, Procurement and other services to its affiliates. The CBS assessment is calculated at the beginning of each year based on the CBS budget. CBS Assessments are not allocated in the usual sense of the word, but are charged on a dollar per unit basis. For example, the facilities assessment is based on square footage of space occupied by employees, network access is based on the number of PCs, and payroll administration is based on the number of employees. (Response to CCS Data Request 4.32.) The metrics used by the Company are shown below.

Corporate Business Services

Service Description	Metric
PC Deskside Support	# of PPW PC's
PC Ownership, Maint, HelpDesk, LAN	# of PC's
Network Access	# of PC's
Basic Telephony Services	# of FTE's
Long Distance Telephone Serv, HQ Bldg's	# of HQ FTE's
Infrastructure Services	# of PC's
Facilities Space	Square Feet
ROW research & enforcement support	ROW Work
Property Management	Property Work
Mail Service	# of HQ FTE's
Record Management Service	# of Employees
OLEE / Travel Administration	Expense Report Analysis
Payroll – Active	# of Employees
Accounts Payable	Invoice Analysis
HR Transaction Service	# of Employees
CCO - Accts Receivable Service	CCO Analysis
SAP Applications	# of Employees
Other Common Business Applications	# of Employees
EDW, Web	# of PC's
Accounting Services - General	# of Employees
Regulated Accounting Services	# of PPW Employees
Property Tax Mgt	Property Tax Work
Budgeting Services	# of FTE's
Procurement Services	Procurement Work

The third category of expense assignment used by PacifiCorp is the allocation of the management fee. The management fee consists of about

20 corporate cost centers that benefit PacifiCorp and its nonregulated affiliates. These common costs are allocated to the affiliates based upon a three-factor formula consisting of operating expenses (excluding purchased power), net assets, and number of employees. CCS Exhibit 3.3 sets forth the three-factor formula used by PacifiCorp and CCS Exhibit 3.4 shows the data used to develop the allocation factors for the years 2001 through 2004. As demonstrated on Exhibit 3.3, the majority of the common costs are allocated to PacifiCorp. For example, using data from the fiscal year ending 2000, PacifiCorp's allocation factor was 98.18%. In 2001, the allocation factor decreased slightly to 98.04%, it declined again in 2002 to 97.36%, and it then declined to 95.39% in 2003 and to 93.49% in 2004. The majority of the change can be attributed to the substantial growth of PPM Energy, Inc. (formerly PacifiCorp Power Marketing). The allocation factors for PPM increased from .43% based upon 2000 fiscal year ending data to 5.61% based upon March 31, 2004 data. The other affiliates (Pacific Klamath Energy, PacifiCorp Financial Services, PacifiCorp Environmental Remediation Company, and PacifiCorp Trans) absorb just a small fraction of the management fee common costs, totaling less than 2% over the five year period depicted on CCS Exhibit 3.3.

III. MANAGEMENT FEE

Q. WHAT SERVICES DOES PACIFICORP PROVIDE ITS AFFILIATES THROUGH THE MANAGEMENT FEE?

A. PacifiCorp provides a wide range of general and administrative services under the management fee arrangement. These services range from legal services to strategic development. The major cost centers that make up the management fee include Internal Communications, Business Planning, PacifiCorp CEO & Staff, Treasury, External & Performance Reporting, Tax Management & Planning, Investor Relations, Human Resources, Government Affairs, Corporate Legal, Audit Services, Open Learning Center, Environmental Policy, Chief Financial Officer Administration, Controller's Administration, US Energy Risk, Director Strategic Analysis, and Group Energy Risk.

Q. HOW WERE COSTS FROM PACIFICORP ALLOCATED TO ITS AFFILIATES FOR THE 2006 PROJECTED TEST YEAR?

A. For the 2006 projected test year the Company used the same allocation factors implicit in the FY 2004 test year. The Company made no adjustment to these allocation factors for the substantial and continued growth that has been experienced by one of its unregulated affiliates—PPM. CCS Exhibit 3.5 depicts the allocation factors used by the Company for the projected FY 2006 test year, for the FY 2004, and for year to date 2005 ending September 2004.

As shown on this exhibit, the allocation factor for PacifiCorp in the projected test year is 96.25%,[1] which is almost identical to the 96.27%

[1] These allocation factors differ from those shown on CCS Exhibit 3.3 because the allocation factors shown on CCS Exhibit 3.3 overlap more than one fiscal year. The allocation factors depicted on CCS Exhibit 3.5 are the allocation factors resulting from applying more than one allocation factor during different time periods.

used in 2004. For the six months ending September 2004, the allocation factor for PacifiCorp was 94.48%--or more than 2% less than what was used in the projected 2006 test year factor. The majority of the difference between year to date 2005 factors and the factors used for the projected test year 2006 is the result of the growth experienced by PPM Energy.

Q. HOW DO THE AFFILIATES AFFECT THE COSTS PACIFICORP INCLUDED IN THE TEST YEAR?

A. As discussed above, PacifiCorp allocates costs to its affiliates. PacifiCorp essentially receives its allocated share of these costs. The PacifiCorp CBS assessments and management fee allocations to PacifiCorp are a function of the affiliates selected to receive services and/or charges and the factors used to allocate costs/charges. If the underlying data used to calculate the allocation factors is incorrect, this will cause either an under charge or an over charge to PacifiCorp. Likewise, if there are affiliates that are not allocated a management fee but should be allocated a management fee, this will again result in an over charge to PacifiCorp and its ratepayers.

Q. DO YOU AGREE WITH THE ALLOCATION METHOD USED TO ALLOCATE MANAGEMENT FEE COSTS TO PACIFICORP AND ITS AFFILIATES DURING THE PROJECTED TEST YEAR?

A. No, I do not. There are several problems with the allocation factors used by the Company to distribute the management fee to its affiliates. First, the allocation factors are largely size-based and therefore, regardless of the benefits received from the services provided, the majority of the management fees are allocated to the largest company—PacifiCorp.

Second, the allocation factors used during the test year are stale. They are based upon the allocation factors implicit in the FY 2004 allocations. The Company's rate case application assumed that there is no change in the FY 2004 three factor formula percentages when escalating FY 2004 results forward to FY 2006 results. The effect of the Company's approach is to understate the allocation of costs to affiliates that are growing at a pace faster than the Company.

Third, there are several affiliates that are not allocated a management fee by PacifiCorp, yet there is no explanation for this lack of allocation in the Affiliated Interest Report.

Fourth, the Company recently changed its management fee allocation and began directly charging costs that were formerly part of the management fee. Close attention must be paid to the time recording practices of PacifiCorp's employees that formerly had their time allocated and are now expected to document their work through an "exception time report". Thus, rather than just recording time without regard to the nature of the work, these employees must specifically identify on their time records if they perform work for a company other than PacifiCorp. Furthermore, it is not evident that the cost centers that were removed from the management fee allocation process could adequately be charged through a direct charge approach. These cost centers are general in nature and would tend to benefit the entire family of PacifiCorp companies.

Q. WOULD YOU PLEASE ADDRESS YOUR FIRST CONCERN ABOUT THE COMPANY'S MANAGEMENT FEE ALLOCATION?

A. Yes. My first concern is that the allocation factor is largely size-based. PacifiCorp consistently receives over 90% of these costs. While PacifiCorp obviously represents a large share of the PacifiCorp family of affiliates, I question the fairness of an allocation method that results in such a large allocation of common costs to the regulated operations of the Company. This size-based allocation factor fails to reflect the benefit that the affiliates of PacifiCorp receive from the shared services. In other words, use of the 3-factor formula implicitly assumes that the larger the affiliate the greater its received benefit from the performance of a particular function within PacifiCorp.

For example, the investor relations department of PacifiCorp provides the following services: maintains and improves investor relationships between the organization and various financial investors and institutions; monitors and assesses changes and trends in ownership of PacifiCorp's stock; schedules program events for investor relations; develops and designs investor fact sheets, presentations, and handouts; and develops and communicates all messages with Shareholder Services in the U.S. and U.K. The director of this section develops and participates in financial broker meetings and develops and makes presentations on behalf of ScottishPower. (Response to CCS Data Request 25.27.)

The director of government affairs job description contains the following responsibilities. “Leads the creation of a public policy and political environment across both federal and state jurisdictions to enable PacifiCorp, PPM Energy, and ScottishPower to achieve their business and financial objectives.” The director oversees policy development, advocates strategies, and political activities in state and federal jurisdictions. He or she is required to possess a broad range of knowledge and skills including an understanding of the impact public policy and regulation will have on achieving the business objectives of ScottishPower and its US businesses. (Ibid.)

The size-based allocation factor ignores the possibility that relatively new competitive companies, like PPM Energy, might benefit disproportionately from the investor relations provided by PacifiCorp. During the FYE 2004, PPM Energy would have been allocated a mere 2.59% of the cost of investor relations services, or only $12,068 and its affiliates (PPM Colorado Wind Ventures, Pacific Wind Development, LLC and Enstor Operating Co. LLC) would have been allocated significantly less.

In addition, although both of these departments, investor relations and government affairs, support ScottishPower, none of their costs have been charged to ScottishPower through the management fee.

Q. WOULD YOU PLEASE ADDRESS YOUR SECOND CONCERN ABOUT THE COMPANY'S MANAGEMENT FEE ALLOCATION?

A. Yes. My second concern relates to the fact that the Company's allocation factors used for the projected test year are stale—they are based upon old data that is not consistent with the projected 2006 test year. There has been substantial growth in PPM, an unregulated affiliate, during the years 2004, 2005, and projected into 2006 and beyond. The Company's proposed allocation factors do not even reflect the growth that has taken place during the fiscal year ending 2004, much less the growth anticipated in 2005 and 2006.

Q. WOULD YOU DESCRIBE PPM IN GREATER DETAIL?

A. Yes. PPM is based in Portland, Oregon and was founded as a business unit of a "century-old regional utility"—PacifiCorp. PPM offers expertise in wholesale power and gas markets. From generation development to long-term energy supply to asset management services and more, PPM provides energy solutions tailored to meet the needs of wholesale and large commercial and industrial customers. According to its website, its portfolio of gas and power assets, 24-hour energy management and scheduling capabilities allow it to deliver products and services that help its customers manage risk in the natural gas and power industries. (http://www.ppmenergy.com/wwa.html)

PPM offers a portfolio of products:

- **Power** – marketing and development of wind and thermal energy facilities, shaping and firming, scheduling and transmission management
- **Natural gas** - marketing, balancing, scheduling and transportation management
- **Natural gas storage and hub services** – asset development, operations and marketing through Enstor.
- **Energy services** such as energy and asset management and structured power solutions tailored to fit customer needs (Ibid.)

ScottishPower's Annual Report discussed the virtues of this affiliate and the growth that it has recently experienced and that it anticipates will continue into the future.

> PPM, our competitive US energy company, continues to build on its impressive record. Operating profit, excluding goodwill amortization, rose by $18 million (41%) to $63 million, with increased contributions from gas storage, optimisation of assets and its steadily growing share of the US wind power market. (ScottishPower Annual Report and Accounts, 2003/04, p. 8.)

On the subject of its wind power operations, the Annual Report stated:

> PPM accounted for almost a third of new wind developments in the US in calendar year 2003, adding control of 528 MW (504 MW in the financial year 2003/04) to its portfolio, which now totals around 830 MW of renewable energy currently under its control. PPM is now pursuing its immediate goal of developing another 500 MW of wind projects. Their completion depends partly on the extension of the PTCs expected to be introduced this year, which would keep PPM on track for its goal of 2,000 MW by 2010. In the longer term, PPM is well placed to take full advantage of the 8,000 MW of potential projects and sites already ear-marked for development. In line with the group's prudent energy management strategy, PPM has already sold forward approximately 80% of its wind power in contracts of between 10 and 25 years, locking in a regular "annuity" value. (Ibid.)

Regarding its gas storage and hub business, ScottishPower reported:

> During the year, an increasing component of PPM's revenues came from its gas storage and hub services business, serving North America from bases in Texas and Canada, which include operating or contracting activities for gas storage and selling capacity forward. Our view is that gas prices will remain volatile, with tight supply and demand, enhancing the value of PPM's owned and contracted gas storage facilities which now total 67 BCF. In addition, as part of PPM's increased origination activities, the number of large wholesale gas customers has increased by approximately 50% over the past year and includes major refineries and municipalities. (Ibid.)

More recently ScottishPower issued a press release on October 5, 2004 announcing the building of two new wind farms and the signing of a power purchase agreement.

> ScottishPower today announced that its US competitive subsidiary, PPM Energy (PPM), is planning to build two new windfarms generating a combined 175 MW following approval of the Production Tax Credit in Congress.
>
> The fully permitted projects, the 75 KW Klondike II wind project in Oregon and the 100 MW Trimont wind project in Minnesota, are expected to be immediately earnings enhancing once completed in 2005. PPM also announced it has signed a 15-year power purchase agreement with Great River Energy, an electric cooperative, for all the Trimont output, and the output from Klondike II is also expected to be sold under long-term agreement currently under negotiation. The capital invested in these two projects is expected to be approximately $200 million and the returns are expected to be consistent with our internal targets. (http://www.scottishpower.com/pages/forinvestors_news_article?documents=33b934_fedd.)

The substantial growth experienced by this Company, combined with the use of stale allocation factors, results in an over allocation of the management fee charged to PacifiCorp during the projected test year.

Additionally, as shown on CCS Exhibit 3.1 there are numerous subsidiaries of PPM – 17 in total. These affiliates still receive significant benefits from the common costs and oversight provided by PacifiCorp. However, only a tiny fraction of these management fee costs are allocated to these affiliates through the allocation to PPM.

Q. WOULD YOU PLEASE ADDRESS YOUR THIRD CONCERN ABOUT THE COMPANY'S MANAGEMENT FEE ALLOCATION?

A. Yes. I am concerned that some affiliates that should be allocated a management fee are not. In response to CCS Data Request 2.37, the Company provided a list of affiliates that are charged costs from PacifiCorp. The spreadsheet provided contained all charges to and from affiliates for the years 2004 and as projected for 2006. Several of the affiliates contained in this response were not allocated a management fee, yet they were charged other costs from PacifiCorp. These affiliates include Interwest Mining, Energy West Mining, PacifiCorp Group Holdings, West Valley Leasing, Enstor Operating Co. LLC, Pacific Wind Development, LLC, PPM Colorado Wind Ventures, PacifiCorp Holdings, Inc., Pacific Minerals/Bridger Coal, Trapper Mining, PacifiCorp Foundation, and ScottishPower.

Some of these affiliates are subsidiaries of other affiliates and according to PacifiCorp their respective allocators (i.e. employees, assets and operating expenses) are included in their parent's allocation factors. These include Enstor Operating Company, LLC, Pacific Wind Development, LLC, and PPM Colorado Wind Ventures. (Response to CCS Data Requests 25.18, 25.19, and 25.20.) All of these companies are subsidiaries of PPM and apparently their allocation factor data is included in the data for PPM. West Valley Leasing is also an affiliate of PPM. It has no employees, yet through a lease arrangement with the Company it charges PacifiCorp approximately $17 million dollars a year for the lease of the West Valley combustion turbines. (Response to CCS Data Requests 2.37 and 25.33.) According to the Company, the management fee that should be assessed West Valley is charged through PPM. (Response to CCS Data Request 25.17.) However, few, if any, costs are implicitly allocated to West Valley as purchased power has been removed from the data used to develop the allocation factor.

Concerning Interwest Mining, this company is a wholly-owned subsidiary that exists for the purpose of providing coal mine management services to PacifiCorp. Its budget is set by PacifiCorp, all expenditures are governed by PacifiCorp and its costs are consolidated into PacifiCorp costs. (Response to CCS Data Request 19.67.) A similar situation exists with Energy West Mining, which provides operating and asset management services for the Deer Creek/Mill Fork Mine under the direction of the Company. (Ibid.)

Trapper Mining, Inc. holds PacifiCorp's interest in the Trapper coal mine, which supplies fuel to the Craig Power Plant. PacifiCorp's share of Trapper Mining Company's actual operating expenses are accounted for as part of delivered fuel expense for the Craig Plant. According to the Company, these "costs do not include either a margin or a profits component." (Response to CCS Data Request 4.19.) In response to CCS Data Request 17.26 the Company indicated that Trapper is not a subsidiary; it is considered an unconsolidated investment and PacifiCorp holds only a 21.4% interest in Trapper Mining. No management fee is charged to Trapper Mining Company.

Pacific Minerals, Inc. is the parent company of Bridger Coal Company. Bridger Coal Company operates the Bridger Mine on behalf of Pacific Minerals, Inc. and Idaho Energy Resources Company. All of the coal output of the Bridger Mine is sold under a long-term coal supply agreement to PacifiCorp and Idaho Power Company for consumption at the Jim Bridger Power Plant. Bridger Coal Company is only billed direct charges for legal services, IT, external consultants and employee benefits. (Response to CCS Data Request 25.22) A management fee is not charged to this Company. According to PacifiCorp, a management fee is not charged for two reasons:

> First, two-thirds of Bridger Coal is a directly-owned subsidiary of its joint-owner parent PacifiCorp. Thus, two-

> thirds of the costs incurred by Bridger Coal roll up to PacifiCorp and are recognized on the books of PacifiCorp. Allocating a management fee to a corporate child is not meaningful since costs of that entity are also costs of the parent. No cost responsibility would be shifted. Second, the other one-third interest in Bridger Coal is owned by Idaho Power, which performs its own management and oversight of Bridge Coal operations. PacifiCorp does not allocate management fee to the one-third interest of Bridger Coal owned by Idaho Power, for which Idaho Power incurs its own corporate management costs. (Supplemental Response to CCS Data Request 25.22.)

PacifiCorp Foundation for Learning is a utility-endowed foundation. It is an independent foundation advancing individual community aspirations through learning. According to the Company, since the Foundation was established in 1988, it has awarded more than 6,000 grants totaling nearly $37 million to communities served by PacifiCorp. This affiliate is not allocated a management fee because: "The Foundation reimburses PacifiCorp for administrative expenses, which includes salaries for two employees, office supplies, travel, etc. The Foundation is an endowment with no operations." (Response to CCS Data Request 25.16.)

PacifiCorp Group Holdings has no employees, but two of its subsidiaries do have employees. PacifiCorp Trans, Inc. and PacifiCorp Financial Services, Inc. each have one employee. No management fee is allocated to PacifiCorp Group Holdings, but a small management fee is charged to PacifiCorp Financial Services, Inc. and PacifiCorp Trans, Inc. As shown on CCS Exhibit 3.1 there are numerous subsidiaries under the direction of PacifiCorp Group Holdings Company, yet only two are allocated any costs. The Company claims that the others are dormant and thus have no operations. However, PACE Group, Inc. is not considered a dormant subsidiary, yet no management fee was allocated to this affiliate.

According to the Company, PacifiCorp Holdings, Inc. is a holding company only. It provides no products or services, it has no employees, and it has no operating expenses or assets. (Response to CCS Data Request 25.21.) PHI is a holding company for four direct subsidiaries: Pacific Klamath Energy, Inc., PacifiCorp, PacifiCorp Group Holdings, and PPM Energy, Inc. No management fee is charged to PHI because if has no employees, assets, or expenses. During the FYE 2004, PacifiCorp charged PacifiCorp Holdings $32,083 for labor, but no management fee.

ScottishPower, PacifiCorp's parent, is also not charged any portion of the Company's management fee. However, as discussed above, many of the cost centers included in the management fee support ScottishPower. The Company has not explained why ScottishPower was not allocated any of the PacifiCorp management fee.

Q. THERE APPEAR TO BE SEVERAL AFFILIATES THAT ARE NOT CHARGED A MANAGEMENT FEE BY PACIFICORP. IS THIS A PROBLEM?

A. Yes, it is. It is a problem with respect to four of the affiliates discussed above. These are: PacifiCorp Group Holdings, PacifiCorp Holdings, Inc., PacifiCorp Foundation, and ScottishPower. These four affiliates all share in the benefits being provided by the functions performed with the allocation of the management fee, yet they do not share in the costs. Each one of these affiliates was charged some costs by PacifiCorp for the FYE 2004. For example, PacifiCorp Holdings, Inc. was charged for a financial analyst's time, an accounting clerk, and property services, totaling $32,083. PacifiCorp Group Holdings was charged for SAP configuration assistance, IT assistance and tax management and planning. (Response to CCS Data Request 4.19 Supplemental.)

Given that some services are provided to these affiliates and charged through the CBS Assessments, it would be logical that these affiliates would also benefit from the services provided under the management fee. As described above, these include functions such as human resource management, business planning, government affairs, external performance reporting, investor relations and group wide tax assistance. All of these companies benefit from the general corporate functions performed by PacifiCorp. The Company has not provided a reasonable explanation as to why a portion of the management fee should not be allocated to these affiliates.

For the other affiliates, the costs of the services provided to PacifiCorp are included in PacifiCorp's costs for ratemaking purposes. If a management fee was allocated to these affiliates, the fee would be effectively recharged to the Company through fuel charges and the West Valley lease. On the surface it would appear that there is no harm to ratepayers by not allocating a management fee to these affiliates. However, the Company's failure to allocate a management fee to these affiliates understates the cost of fuel and the West Valley lease relative to what a competitor might charge. Therefore, if the Commission examines the cost of coal or the West Valley facilities from an affiliate and compares this to other competitive options, the lack of a management fee allocation would tend to understate the cost of the affiliate services. To overcome this problem, the Commission should require the Company to allocate the management fee to these affiliates in the future. This would provide a more apples-to-apples comparison of the charges from these affiliates to other competitive options.

Q. WOULD YOU PLEASE ADDRESS YOUR FOURTH CONCERN ABOUT THE COMPANY'S MANAGEMENT FEE ALLOCATION?

A. Yes. In 2004 the Company began directly charging affiliates for certain services rendered that were formerly charged under the management fee. CCS Exhibit 3.6 shows the change between the costs charged in 2003 as a management fee and the costs charged in 2004 as a management fee. As a result of this change in allocating the management fee, the total pool of management fee costs declined from $40.7 million for the FY 2003 to $22.6 million for the FY 2004.

As shown on this exhibit, the following cost centers no longer belong to the management fee category: tax management and planning, treasury, corporate legal, PacifiCorp CEO & Staff, audit services, US energy risk, group energy risk and environmental policy.

Generally, it is preferable to directly charge an affiliate for services rendered where possible and to the extent that the time reporting practices are accurate. However, in this particular instance PacifiCorp took $18.1 million of corporate common costs and has determined that these costs can be directly charged. Given the nature of these costs, it would seem more reasonable to allocate these costs to all affiliates, after all direct assignments have been made. Since these types of costs are for the benefit of the entire company as a whole, it is difficult to see how a direct assignment approach would apportion these costs fairly. Furthermore, there may be situations where even though there are benefits flowing from the functions performed by a particular cost center, no cost is charged to the unregulated affiliates. (Costs which are not allocated or directly charged remain with PacifiCorp.)

For example, one of the cost centers that no longer appears in the group that is allocated is PacifiCorp CEO and Staff. For the year 2004, none of these costs were directly assigned or even allocated to the unregulated affiliates of the Company. While many of the functions performed by the CEO may be necessary for a company the size of PacifiCorp, they are also very valuable to the unregulated companies, like PPM. Yet, under this new direct assignment approach for this cost center no costs were allocated to the unregulated affiliates.

The Company appears to agree that costs included in the management fee are for the good of all companies. In response to CCS Data Request 2.39, the Company explained that: "Some corporate costs, however, cannot be specifically assigned since they benefit the entire company as a whole. The purpose of the Management Fee allocation is to allocate an equitable portion of PacifiCorp corporate costs that benefit both PacifiCorp and its affiliates, to the nonregulated entities based on a three-factor formula." (Response to CCS Data Request 2.39.)

Q. YOU HAVE IDENTIFIED SEVERAL PROBLEMS WITH THE COMPANY'S ALLOCATION OF ITS MANAGEMENT FEES. DO YOU HAVE A RECOMMENDATION ON HOW THE COMMISSION CAN CORRECT FOR THESE PROBLEMS?

A. Yes, I do. First, to overcome the problem associated with the Company's use of stale allocation factors, I recommend that the Commission update the allocation factors and bring them to a 2006 level for each of the affiliates that is allocated a portion of the management fee. This will bring the level of the management fee allocations consistent with the projected 2006 test year. Similarly, it will help offset the problem identified with respect to PPM and its substantial growth relative to the Company.

CCS Exhibit 3. 7 sets forth the allocation factors that I recommend for use in the projected test year 2006. I have estimated the data (assets, expenses, and employees) that makes up the allocation factors using a couple of methods. For employees, I have used the number of employees recommended by Larkin & Associates for the FY 2006. For the other affiliates, I have used the number of employees projected for the FY 2006 as provided in response to CCS data request 25.11.

For O&M expenses I have increased the FYE 2004 level by the amount of the increase in O&M expenses recommended by Larkin & Associates for PacifiCorp. For the other affiliates, I used project expenses provided by the Company in response to CCS Data Request 25.10.

For the 2006 asset allocation factor, I increased the FY 2004 assets for PacifiCorp by the amount of net plant additions allowed by Larkin & Associates. For the affiliates, I used projected data for the affiliates provided by the Company to determine the 2006 level of assets.

To address the second and third problems associated with the size-based nature of the allocation factor and the fact that several affiliates are not allocated any of the management fees, I recommend that the Commission assign a 5% allocation factor to this group. This would help offset the fact that the small affiliates of PacifiCorp, like PPM, receive significant benefits for the services provided under the management fee, yet these benefits are not reflected in the allocation methodology. Likewise, allocating this group 5% of the management fee will also offset the fact that there are affiliates that are not allocated a management fee, yet obviously benefit from these functions.

I have also allocated $2.0 million of the management fee to ScottishPower. In the Company's compliance filing in Docket No. 03-035-

26, the Company indicated that the cross charge to ScottishPower would be under $2.0 million. However, since no management fee was charged to ScottishPower, I have used the $2.0 million estimate provided in the Compliance Filing. (PacifiCorp, Compliance Filing, Docket No. 03-035-26, p. 6.)

A comparison of the allocation factors used by the Company for the projected test year compared to my recommendation is shown on CCS Exhibit 3.8. As shown, my composite recommended 3-factor allocation factor produces a significantly higher allocation factor for PPM in 2006 than that used by the Company. Likewise, it reduces the allocation factor to PacifiCorp from 96.25% to 87.31%. As shown on this exhibit, my recommendation reduces the management fee charged to the Company in FY 2006 by $2,162,014. On a Utah basis, my recommendation reduces test year expenses by $899,587.

Q. ONE OF THE CONCERNS YOU RAISED ADDRESSED THE CHANGE IN THE METHOD OF CHARGING FOR THE MANAGEMENT FEE FROM AN ALLOCATION TO A DIRECT ASSIGNMENT FOR SOME COST CENTERS. DO YOU HAVE A RECOMMENDATION ON HOW THE PROBLEMS YOU IDENTIFIED CAN BE OVERCOME?

A. Yes. As discussed earlier, the cost centers that the Company now proposes should be directly assigned as opposed to allocated are general in nature and benefit the entire operations of PacifiCorp, including the unregulated operations. To the extent that costs can be directly assigned, these costs should be removed prior to any allocation of the remaining costs included in the cost center. This would ensure that work performed specifically for the unregulated affiliates is charged to those affiliates, but at the same time the general benefits associated with the functions performed in these general cost centers are shared by all companies, not only by PacifiCorp.

Therefore, I recommend that for the cost centers where the Company employed the direct assignment approach these costs be allocated using my recommended 3-factor allocation formula. Because I did not have the necessary data to develop[2] the starting point for the 2004 allocation, I have estimated these costs by using the amounts charged in 2003 and inflating them to the FY2006 level prior to applying my recommended allocation factors. My recommended adjustment is shown on CCS Exhibit 3.9. As shown, my recommendation reduces PacifiCorp test year expenses by $2,883,852. On a Utah jurisdictional basis, the adjustment reduces expenses by $1,199,934.

IV. ADJUSTMENTS TO NORMALIZE MANAGEMENT FEE EXPENSES

Q. WHAT IS THE NEXT ADJUSTMENT THAT YOU ARE RECOMMENDING?

A. The next adjustment that I propose relates to normalizing the 2004 test year management fees used to project the 2006 expenses. This adjustment, shown on CCS Exhibit 3.10, adjusts the Company's 2004

[2] CCS has issued another data request to PacifiCorp to attempt to ascertain this information. I will update the amount of my recommended adjustment when the necessary data is provided

management fee expenses to a level more appropriate for use with the projected 2006 test year. As shown on this exhibit, the management fee for certain categories of expenses increased dramatically between FY 2003 and FY 2004. For example, External and Performance Reporting increased from FY 2003 to FY 2004 by 295%. Likewise, the cost center Human Resources Compensation increased by 101% from 2003 to 2004. Other cost centers that showed substantial increases include Government Affairs State Agencies, Human Resources, and Director Strategic Analysis.

In developing the level of the management fee for the projected test year, the Company inflated the 2004 expense levels to arrive at the 2005 and 2006 expenses to include in the projected test year. To overcome the problems with the significant increase in some of the management fee expense levels, I annualized the expenses incurred during the first six months of FY 2005. I then used the Company's inflation factor for 2006 to inflate the annualized FY 2005 expenses to a FY 2006 level. The result of this process is shown on CCS Exhibit 3.10. As shown, the result of my analysis indicates that an adjustment to management fees is necessary. In particular, PacifiCorp's management fee expense should be reduced by $2,865,893. On a Utah basis, this results in a reduction to test year expenses of $1,192,462.

Q. YOUR CCS EXHIBIT 3.10 SHOWS THAT THE MANAGEMENT FEE HAS DECLINED BY 44% FROM FY 2003 TO FY 2004. UNDER THESE

CIRCUMSTANCES, IT DOES NOT SEEM LIKE YOUR ADJUSTMENT IS NECESSARY. WOULD YOU PLEASE EXPLAIN WHY IT IS NEEDED?

A. Yes. CCS Exhibit 3.10 does show that the total management fee decreased by 44% from FY 2003 to FY 2004. However, as discussed above, in FY 2004 the Company began directly charging its affiliates for certain costs included in several of the cost centers formerly included in the management fee. For these cost centers there are no expenses shown for FY 2004. It is this phenomenon that suggests that the management fee has declined. Consequently, comparing FY 2003 to FY 2004 gives misleading information.

If, however, the cost centers that were removed from the management fee in FY 2004 are also removed from the total management fee for FY 2003 it is possible to make a comparison of the total fees between the two years. As shown on line 42 of CCS Exhibit 3.10, this more appropriate comparison indicates that the management fee expenses actually increased by 23%.

<u>V. PACIFICORP ENVIRONMENTAL REMEDIATION COMPANY</u>

Q. WHAT HAS THE COMPANY PROPOSED CONCERNING THE ENVIRONMENTAL CLEAN-UP SETTLEMENT FUNDS PERCO RECEIVED FROM PACIFICORP?

A. The Company has proposed to reduce rate base by the unused insurance settlement for the environmental clean-up funds that were transferred from PacifiCorp to PERCO. In 1996, the Company received an insurance settlement of $33 million to cover the cost of Company clean-up sites. In 1998, additional insurance proceeds in the amount of $5 million were transferred from PacifiCorp to PERCO. Additional funds were recorded in 1999 and 2002 of $10.0 million and $225,000, respectively. On all of these settlements, as remediation work is performed, the funds from the insurance settlement are used, reducing the fund balance.

Q. HOW DID THE COMPANY ACCOUNT FOR THE ENVIRONMENTAL CLEAN-UP COSTS IN ITS RATE FILING?

A. PERCO maintains the funds and pays the actual environmental remediation costs from those funds. Therefore, the actual accounting for the environmental remediation costs paid by PERCO does not appear on PacifiCorp=s books, but on the books of PERCO. In its rate filing, the Company made an adjustment to reduce PacifiCorp=s rate base by $14,527,241 on a total Company basis and by $6,044,601 on a Utah basis. The adjustment proposed by the Company only accounts for the first two settlements--$33.0 million in 1997 and $5.0 million in 1998. The latter two settlements of $10.0 million and $225,000 are not included in the PERCO balance used to reduce rate base.

Q. DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT?

A. In part. The unused environmental clean-up funds represent a cost-free source of capital for the Company which should be used to offset rate base. The fact that the funds were transferred to a subsidiary should not impact their ratemaking treatment. In response to CCS Data Request

31.14 PacifiCorp gave the following reasons for transferring the proceeds to PERCO.

> First, the transfer allowed for the proceeds to be used specifically for environmental cleanup and remediation which would in turn reduce yearly costs and the burden on ratepayers. All proceeds are spent to address specific environmental liabilities of PacifiCorp that require action under federal, state or local laws and regulations. Second, it focused the efforts to a specialized entity, PERCo, whose primary purpose is to implement cost effective and environmentally protective cleanups. (Response to CCS Data Request 31.14.)

I agree with PacifiCorp that the unused settlement proceeds should be used to offset rate base. However, I disagree with three other aspects of the PERCO settlements. First, in order to ensure that ratepayers receive the full benefit of these funds the Commission needs to recognize the interest income that has been earned on these settlement funds. PERCO=s interest income is a direct result of the transfer of the funds from PacifiCorp. If PacifiCorp had not transferred these funds to a subsidiary, PacifiCorp would have earned that interest income as opposed to its subsidiary. Second, the Company has not adequately explained why it treated the $10.225 million as nonregulated. Third, the Company has not reflected accretion in the balance of the settlement funds as an offset to rate base.

With respect to the interest income earned, I recommend that the Commission include the interest income in the regulated operations of PacifiCorp. If these funds were not transferred to its affiliate, the interest income would be recorded on the books of PacifiCorp. Exhibit CCS 3.11

depicts the calculations needed to attribute this interest income to ratepayers. As shown, on a total Company basis income should be increased by $884,912. On a Utah basis the amount is $368,201.

Concerning the funds the Company has treated as nonregulated, I recommend that the Commission treat them as regulated. In response to CCS Data Request 31.16, the Company explained that the nonregulated amounts related to project costs incurred by PERCO after receipt of the insurance settlement. The funds are considered nonregulated by the Company "[s]ince the settlement benefits the ratepayers, project costs incurred after the settlement, which was received in 1998, should not be included in regulated amounts." (Response to CCS Data Request 31.16.) The Company's response does not adequately explain why the $10.225 million of additional funds should be considered nonregulated. In fact, with respect to the $225,000, while treated as nonregulated in adjustment 8.2, it is shown under the regulated column in response to CCS Data Request 31.16. Until the Company is able to adequately demonstrate that these funds should be considered nonregulated, I recommend that the Commission treat them as regulated and offset them against rate base.

Finally, the Company has not explained why accretion should not be used to offset the regulated rate base. In response to CCS Data Request 31.16, PacifiCorp explained that accretion represented the change in the net present value of the liability due to the time value of money. By backing out the accretion, the balance has no component of future dollar value. Unless the Company is able to demonstrate that the accretion of $2,905,855 should not be used to offset rate base, I recommended that it be included in the offset. CCS Exhibit 3.11 shows the total company reduction to rate base for both the additional settlement funds and the accretion is $7,411,210. The Utah allocation portion is $3,083,710.

VI. WEST VALLEY LEASE

Q. WHAT ADJUSTMENT ARE YOU PROPOSING WITH RESPECT TO THE WEST VALLEY LEASE ARRANGEMENT?

A. As described in greater detail in the testimony of CCS witness Falkenberg, the Company leases combustion turbines from West Valley, a subsidiary of PPM. In May 2002, PacifiCorp entered into a 15-year operating lease with West Valley for the lease of five generating units, each rated at 40 MW. Under the terms of the lease agreement the West Valley plant is operated by PacifiCorp, while the affiliate West Valley holds the assets. The adjustments that I discuss below may not be necessary if the Commission adopts the recommendations of the Committee's witness Falkenberg concerning the appropriate cost to include in the test year related to the West Valley plants.

The arrangement with West Valley calls for PacifiCorp to make quarterly lease payments of $749,150 to West Valley for each of the five units. The Company has included the lease payments, and related property tax expense in the rate case, under rent expense. The Company assumes that the lease payment including the property taxes would increase by 3.5% from 2004 to 2006. As shown on CCS Exhibit 3.12, for FY 2004 the lease payment plus property taxes were $17,010,041. The Company proposes to increase this amount to $17,602,253 for the projected 2006 test year. The inflation adjustment from 2004 to 2006 is unnecessary as the lease agreement does not call for any escalation in the lease payments. Accordingly, as shown on CCS Exhibit 3.12, I have reduced the amount of the lease payment by $362,314. On a Utah basis this adjustment reduces test year expenses by $153,593.

Also shown on this exhibit is an adjustment to property taxes of $437,800 on a Utah basis. At this time I am not recommending the adjustment, as there is still outstanding discovery on this issue. However, depending upon the responses to discovery, it may be necessary to update my testimony to account for this adjustment. The purpose of this proposed adjustment is to reduce the property taxes included in the lease payment to the amount shown on the income statement of West Valley.

VII. BRIDGER COAL COMPANY

Q. WHAT ADJUSTMENT IS THE COMPANY PROPOSING WITH RESPECT TO THE JIM BRIDGER MINE (ADJUSTMENT 8.4)?

A. PacifiCorp owns a two-thirds interest in the Bridger Coal Company, (BCC), which supplies coal to the Jim Bridger Generating Plant. The remaining one-third of Bridger Coal Company is owned by Idaho Power, which also shares the same interest in the Jim Bridger Generating Plant. Bridger Coal

Company operates the Bridger Mine on behalf of Pacific Minerals, Inc. (PMI) and Idaho Energy Resources Company (IERCO). All of the coal output of the Bridger Mine is sold under a long-term contract to PacifiCorp and Idaho Power for consumption at the Jim Bridger Power Plant.

PacifiCorp's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc., a subsidiary of PacifiCorp. According to Mr. Weston:

> Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. The normalized coal costs for Bridger Coal Company include the operating and maintenance costs of mining, but provide no return on investment. Therefore, this adjustment is necessary to properly reflect the Bridger Coal Company investment in base year rate base. (Weston Direct Testimony, pp. 30-31.)

As shown on CCS Exhibit 3.13 the Company is proposing to increase the Utah rate base by $31,368,045 for the addition of this coal mine investment.

Q. HAS THE COMMISSION ACCEPTED THIS ADJUSTMENT IN PAST RATE PROCEEDINGS?

A. Yes, it has. In Docket No. 99-035-10, the Commission found: “All parties agree to an adjustment to include the Company's investment in the Bridger Coal Company in rate base. (See Appendix 1, Section C, number 8.)” Likewise, in Docket No. 97-035-01, the Commission noted that the rate base adjustment for the investment in Bridger Coal Company was undisputed: “An investment in Bridger Coal Company has been recorded on the books of Pacific Minerals, Inc., a PacifiCorp subsidiary, rather than on the books of Electric Operations. An undisputed adjustment brings the investment into rate base. It increases rate base by $ 11,979,921."

Q. DO YOU AGREE WITH THE ADJUSTMENT PROPOSED BY THE COMPANY?

A. No. Moreover, I do not agree with the methodology used by the Company to account for the Bridger Coal Company. PacifiCorp has essentially included all of the costs of Bridger Coal Company in its regulated operations. The cost of the coal and the coal operations are included in the fuel expense and the investment in the Bridger Coal Company is included in rate base. The Company has, in effect, treated the cost associated with the Bridger Coal Company as if it were integrated with the utility and part of its regulated operations. The Company's response to CCS Data Request 25.22 indicates that PacifiCorp itself holds this interpretation of how it has treated the operations of Bridger Coal Company. In this response the Company explained:

> For ratemaking purposes, PMI/Bridger is added to PacifiCorp's rate base, rather than treating the purchase of coal as an affiliate transaction. The Utah Commission has accepted this treatment historically. (Response to CCS Data Request 25.22.)

The Company apparently believes that rather than have this transaction be treated by the Commission as an affiliate transaction, it should be treated as part of the regulated operations of the utility.

When asked why it did not allocate PMI/BCC a management fee from PacifiCorp, the Company essentially gave a similar explanation that

BCC is treated as if it were part of the utility's regulated operations. In response to CCS Data Request 25.22, the Company explained:

> Pacific Minerals, Inc./Bridger Coal is not charged the management fee for two reasons. First, two-thirds of Bridger Coal is a directly-owned subsidiary of its joint-owner parent PacifiCorp. Thus, two-thirds of the costs incurred by Bridger Coal roll up to PacifiCorp and are recognized on the books of PacifiCorp. Allocating a management fee to a corporate child is not meaningful since costs of that entity are also costs of the parent. No cost responsibility would be shifted. Second, the other one-third interest in Bridger Coal is owned by Idaho Power, which performs its own management and oversight of Bridger Coal operations. PacifiCorp does not allocate management fee to the one-third interest of Bridger Coal owned by Idaho Power, for which Idaho Power incurs its own corporate management costs. (Supplemental Response to CCS Data Request 25.22.)

While the Company has treated the expenses and investment as if they were part of the utility operations, it appears to have excluded one key component of the ratemaking equation -- the income generated from the Bridger Coal Company's operations.

Q. DID THE COMPANY EXPLAIN WHY IT DID NOT INCLUDE THE INCOME IN ITS REGULATED OPERATIONS?

A. There is no discussion of this matter in the testimony of the Company's witnesses. However, in response to CCS Data Request 31.25, when asked why the income from Bridger Coal Company was not included in the Company's income for ratemaking purposes since the investment is included in rate base and the expenses are included in fuel, the Company responded as follows: "PacifiCorp records a credit to delivered fuel expense equal to PacifiCorp's share of the Fuels Credit." (Response to

CCS Data Request 31.25.) The Company's response suggests, but does not explicitly state, that some form of credit related to earned income is included in the delivered fuel price. The Committee has issued additional discovery to determine exactly what is included in the "Fuels Credit." Until such time as the Company can demonstrate that the full benefit of the income is used to offset the delivered fuel price, I recommend that the Commission include the income from BCC in the Company's regulated operations.

Q. WHY WOULD YOU WANT TO INCLUDE THE INCOME FROM THE BRIDGER COAL COMPANY IN WITH THE REGULATED OPERATIONS OF THE COMPANY?

A. There are several reasons. First, as noted above, the Company has essentially treated all other aspects of BCC as regulated; I see no reason to treat the income any differently. Because BCC's sole function is to provide coal to the Bridger power plant, all profits the company earns are generated from the regulated operations of PacifiCorp and Idaho Power Company (Idaho Power). BCC does not sell coal to nonregulated unaffiliated companies. PacifiCorp has essentially indicated that these coal operations should not be treated as an affiliate transaction, but instead as part of its regulated utility operations. Moreover, as described in greater detail below, the Idaho Public Service Commission treats Idaho Power's investment, expenses, and income as if they were part of the utility's regulated operations.

Second, the Company owns two other mining affiliates, Energy West Mining Company (Energy West) and Interwest Mining Company (Interwest). These affiliates, which are also subsidiaries of PacifiCorp, are consolidated directly on the books of PacifiCorp.

Interwest is a wholly-owned subsidiary that exists for the sole purpose of providing coal mine management services to PacifiCorp. Its annual budget is governed by the Company and its costs (with no profit margin) are consolidated into PacifiCorp costs. Likewise, Energy West operates the Deer Creek/Mill Fork Mine at the direction of the Company. Because the Company owns the coal assets, the transactions between the Company and Energy West do not include the purchase of coal, only operating and management services. The services provided by Energy West are performed on a cost-reimbursable basis, without margin or profit. (Response to CCS Data Requests 4.17, 4.19, and 19.67.) Including BCC's income in the Company's regulated operations would bring BCC's treatment more in line with that of Interwest and Energy West.

Third, the arrangement between the Company and BCC assures BCC and PMI of a market for their coal—all of the coal output from the mine is sold under a long-term contract to either PacifiCorp or Idaho Power. Consequently, BCC/PMI face less risk associated with their coal mining operations compared to a firm that does not have a guaranteed market for its product. By including the investment, expenses, and income in the regulated operations of the Company, the Commission can protect customers against a windfall profit, yet at the same time ensure that the utility is allowed to earn a reasonable return on its investment in the coal mining operations.

Fourth, unless the Commission includes the income from the operations of Bridger Coal Company in PacifiCorp's regulated operations, the Company will earn a double return on its investment in the Bridger Coal Company: once through the return that is generated by including the investment of BCC in rate base and then again through the income that is generated through the sales of coal to PacifiCorp and Idaho Power. Clearly, such a situation is unfair and unreasonable to ratepayers. For the FY 2004, BCC earned a return on investment in excess of 27%. Adding the income that would be generated from allowing the Company to earn a return on BCC's investment through inclusion in rate base produces a return of 44.7%.

Fifth, in order to ensure that ratepayers are not being harmed by the affiliate arrangement with PMI/BCC it is appropriate that the Commission include the income generated from Bridger Coal Company in the regulated operations of the Company. PacifiCorp has treated all other aspects of the coal operations of this affiliate as if it were regulated and an integrated part of the utility; there is no reason to treat the income differently.

Q. ARE YOU AWARE OF ANY SITUATIONS SIMILAR TO THIS WHERE A COMMISSION HAS INCLUDED THE INCOME OF A COAL AFFILIATE IN THE REGULATED OPERATIONS OF THE UTILITY?

A. Yes. In the past the Idaho Public Service Commission has made this adjustment with respect to two coal companies. One of the coal companies is Washington Irrigation & Development Company (WIDCo) a wholly-owned subsidiary of Washington Water Power Company (WWP) and Pacific Power & Light Company (PP&L). The other coal company is Bridger Coal Company owned by Idaho Power Company through Idaho Energy Resources Company (IERCO).

In determining how the costs of WIDCo should be treated for ratemaking purposes, the Idaho Commission found that the revenues, expense, and investment of the coal company should be included with the regulated operations of the utility:

> The Commission finds the treatment of WIDCo under the "California approach", as proposed by Commission Staff, to be appropriate under the circumstances in this case. The Staff argument that the coal mine bears no greater risk to the investor than does the utility is convincing since, in the end, the common stockholders are inseparable. WIDCo should be allowed to recover its costs of production, including its cost of capital, from ratepayers. The most efficient means by which we might assure a fair return to WIDCo and reasonable electricity prices to ratepayers is to include the WWP investment in its WIDCo coal subsidiary in WWP's rate base and consider WIDCo expenses and revenue as those of WWP during the ratemaking process. (Idaho Public Utilities Commission, Case Nos. U-1008-155, U-1008-156; Order No. 16829, October, 1981.)

In supporting its decision with respect to WIDCo, the Idaho Commission pointed to similar treatment afforded Idaho Power Company and its affiliate Idaho Energy Resource Company which is the 1/3 owner of the Bridger Coal Company. The Commission noted:

> We note that our treatment of WIDCo is consistent with that accorded the coal operations of other utilities in a variety of regulatory contexts, … In like manner, Idaho Power Company owns coal reserves (adjacent to the Jim Bridger coal-fired steam plant in Wyoming) through a subsidiary, Idaho Energy Resources Company (IERCo). This Commission, since 1976, has been treating IERCo as an integral part of Idaho Power Company's investment in the steam plant. Idaho Power Company has accepted this procedure. Finally, Utah Power & Light Company (UP&L) owns coal mines directly which provide fuel for that company's coal-fired steam plants. These mines are included as utility plant by the regulatory bodies having jurisdiction over UP&L. Other than the existence of separate corporate identities for WIDCo and IERCo, the basic purpose of all these coal operations, is identically the same, namely, to provide fuel to the steam plants of the parent utility. It is clear, therefore, that use of the "California approach" with respect to WWP's subsidiary, WIDCo, is not a departure from typical ratemaking treatment accorded such coal operations by regulatory bodies. (Ibid.)

In the above case the utility requested a rehearing. The Idaho Commission denied the request. In its request for rehearing, the utility made two arguments. First, it alleged that the Commission failed to address the presence of "arms-length bargaining." Second, it alleged that the Commission failed to base its findings of fact on substantial evidence. In addressing its reasons for denying the request for rehearing, the Idaho Commission addressed the two commonly used methods of determining the reasonableness of transactions between regulated utilities and their affiliates:

> The "traditional approach" compares the prices and/or levels of profits of the affiliate transactions with the prices and/or profits of comparable non-affiliated enterprises. Washington Water Power Company v. Idaho Public Utilities Commission, 101 Idaho 567, 617 P.2d 1242 (1980); Application of Montana-Dakota Utilities Co., 102 N.W.2d 329 (1960). The "California approach" determines the reasonableness of an affiliated transaction by treating the subsidiary as a part of the utility for ratemaking purposes. Pacific Northwest Bell Telephone Company v. Sabin, Or. App. 534 P.2d 984 (1975); Illinois Bell Telephone Company v. Illinois Commerce Commission, 303 N.E.2d 364 (1973); City of Los Angeles v. Public Utilities Commission, 497 P.2d 785 (1972) (Idaho Public Utilities Commission, Case Nos. U-1008-155, U-1008-156; Order No. 16945, December, 1981.)

The Idaho Commission determined that it was unable to ascertain the reasonableness of the price paid for WIDCo coal based on a comparison of prices or affiliate profits with those of non-affiliate transactions. Therefore, the Idaho Commission adopted the "California approach" which essentially treats the subsidiary as a part of the utility for ratemaking purposes. In its Order, the Idaho Commission found that the "California approach" should apply to the instant situation because the coal affiliate has an assured and captive market and meaningful comparisons with non-affiliate prices are impossible. Citing several cases[3], the Commission noted that this approach has been determined

[3] Pacific Northwest Bell Telephone Co. v. Sabin, Or. App. 534 P.2d 984 (1975); Illinois Bell Telephone Company v. Illinois Commerce Commission, 303 N.E.2d 364 (1973); City of Los Angeles v. Public Utilities Commission, 497 P.2d 785 (1972); Pacific Telephone and Telegraph Co. v. Public Utilities Commission, 401 P.2d 353 (1965).

fair and reasonable where the utility and a subsidiary have substantially integrated operations.

The above case was appealed to the Supreme Court of Idaho, where it was affirmed in part and reversed in part. The court reversed the Idaho Commission's decision adopting the "California approach" and remanded it to the Commission for determination of a fair rate of return for WIDCo.

In reversing and remanding the decision of the Idaho Commission, the Court found that the "California approach" would be reasonable where the subsidiary was vertically integrated with the utility:

> Where an electrical utility has created a separate corporate identity for its wholly-owned coal supply operation, and where that subsidiary continues as an integrated part of the unified production and distribution function of the utility, it would not be unreasonable or arbitrary for the Commission to combine the subsidiary's rate base, income and expenses with those of the utility for rate-making purposes. (The Washington Water Power Company, Appellant, V. Idaho Public Utilities Commission, Respondent, No. 14462, Supreme Court Of Idaho, 105 Idaho 276; 668 P.2d 1007; 1983 Ida. Lexis 495, August 24, 1983.)

The Court determined that the vertical integration needed to use the California approach was not sufficiently present in the WIDCo case. The Court found that, unlike the current situation, there were several other "non-affiliated" utility companies involved. The Court noted that WIDCo did not supply coal exclusively to its parent, but also supplied coal to eight other independent entities, each of which would have an interest in keeping its coal expenses as low as possible. As noted above, the situation described by the Court is not present with respect to BCC. There are no independent entities that purchase coal from Bridger Coal Company. BCC is two-thirds owned by PMI which is 100% owned by PacifiCorp. The other one-third of BCC is owned by IERCO which is 100% owned by Idaho Power. In both cases, 100% of the coal from the mine is sold to the utility operations. Furthermore, in the case of Idaho Power Company, the income, expenses and rate base are treated as part of the utility operations. Therefore, the cost of coal is limited to actual cost plus a return on investment equal to the utility's return.

The Court determined that in the case of WIDCo the appropriate approach to determining the reasonableness of the coal prices would be to determine a fair rate of return for the coal company. However, the Court specifically noted that in the WIDCo case there was a lack of sufficient vertical integration to justify treating the coal operations as part of the utility operations. That distinction does not exist with respect to BCC—even PacifiCorp is requesting that the investment be included in rate base. Similarly, due to the integration of the companies, PacifiCorp does not allocate any management fees to Bridger Coal Company. If BCC were not integrated with the operations of PacifiCorp, it would charge BCC for the common costs which it charges its other affiliates.

Q. HAS THE IDAHO COMMISSION CONTINUED TO USE THE "CALIFORNIA APPROACH" AFTER THE SUPREME COURT DECISION?

A. Yes. The Idaho Commission has consistently, since 1976, treated Idaho Power Company's investment in BCC through Idaho Energy Resources Company as part of the utility operations. In a 1986 Order, which followed the Supreme Court decision, the Commission found:

> Investment in the subsidiary Idaho Energy Resources Company (IERCo) was included in net electric rate base. That investment was reduced by the amount of notes payable to the parent company ($7,848,056) and the associated interest income adjustment ($862,764) so that subsidiary rate base and earnings reflected only the cash required to fund the subsidiary for the year 1984. In other words, if the Company consolidated the subsidiary or if the subsidiary distributed its earnings to the parent, the 1984 results would be the same as under the Company's presentation. (Idaho Public Utilities Commission, Case No. U-1006-265; Order No. 20610, July, 1986.)

Most recently, in 2004, the Idaho Commission made a similar finding with regards to IERCO and Bridger Coal Company. The adjustments had been used for so long that they had almost become perfunctory requiring little discussion as they were unopposed. In this 2004 Order the Idaho Commission found that the primary purpose of IERCO was to mine coal for the Bridger Power Plant. Likewise, it determined that Idaho Power treats IERCO's coal operations as a part of Idaho Power's utility operation and adds current year IERCO earnings to electric operating income and its investment in IERCO to net electric rate base. (Idaho Public Utilities Commission, Case No. Ipc-E-03-13; Order No. 29505, May 25, 2004.)

Q. WHAT ABOUT WIDCO? DID THE COMMISSION CONTINUE TO USE THE CALIFORNIA APPROACH WITH WASHINGTON WATER POWER COMPANY AFTER THE SUPREME COURT DECISION?

A. My research indicates that the WIDCo issue was settled following the Supreme Court decision. In Order No. 19411, the Idaho Commission found: “The Company and the Staff stipulated on ratemaking treatment of the Company's interest in the WIDCo coal mining operation. We find that the stipulation is reasonable and accept it. We commend the Company and the Staff for their successful efforts to settle an issue that has twice gone to the Supreme Court of Idaho in recent years.” (Idaho Public Utilities Commission, Case No. U-1008-219; Order No. 19411, January, 1985.)

Q. HAS THE “CALIFORNIA APPROACH” BEEN USED BY OTHER COMMISSIONS WHERE THE UTILITY HAS AN INTEREST IN THE JIM BRIDGER PLANT?

A. Yes. The approach advocated by the Idaho Commission appears to have been used by the Washington Utilities and Transportation Commission:

> This adjustment relates to determination of the appropriate cost for coal burned to produce power at the Jim Bridger generating facility. The facility consists of four units, owned two-thirds by PP&L and one-third by Idaho Power Company. Coal for the plant is provided by the Bridger coal mine, which is owned two-thirds by subsidiaries of PP&L, which are NERCO and Pacific Minerals. Pacific Minerals operates the Bridger coal mine. Because of this affiliation, the Commission has previously declined to rely on the stated coal price set by Bridger Coal Company. In the past, the Commission has determined the appropriate cost of coal for ratemaking purposes by allowing the Bridger Coal Company

> to earn a return on its mining investment based upon PP&L's overall cost of capital. (Washington Utilities and Transportation Commission, Cause No. U-86-02, September 19, 1986.)

Q. IT IS OBVIOUS THAT THE AFFILIATE RELATIONSHIP BETWEEN PMI/BRIDGER COAL COMPANY AND PACIFICORP LENDS ITSELF TO LIMITING THE RETURN ON THE INVESTMENT IN THE COAL OPERATIONS TO THAT OF THE UTILITY. HOW DO YOU RECOMMEND THAT THIS BE ACCOMPLISHED?

A. As explained earlier, the Company has proposed that the investment in Bridger Coal Company be included in rate base, thus agreeing that these operations should be treated as if they are regulated. However, it is unclear whether or not the Company has included the income generated by PMI/BCC to reduce fuel expenses. Unless fuel expense is reduced or income is increased, PacifiCorp will be provided with a double recovery of the return on the investment in the BCC.

Therefore, until the Company demonstrates that it has properly treated this income, I recommend that the Commission include PMI’s two-third’s share of Bridger Coal Company’s income in the regulated income of the Company. As shown on Exhibit CCS 3.13, the Commission should increase test year net operating income by $16,634,109 on a total Company basis and by $6,847,733 on a Utah basis.

It is important to note that the adjustment that I am recommending is quite conservative. My adjustment holds the level of income generated in 2004 constant over the projected test year despite a substantial projected increase in the investment in the Bridger Coal mine.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DOES NOT ADOPT YOUR PRIMARY RECOMMENDATION?

A. Yes. If the Commission does not adopt my recommended income adjustment, then it should clearly exclude from rate base the proforma adjustment proposed by the Company. If the Commission allows the Company to include the investment for the Bridger Coal mine in rate base without an offsetting adjustment for the income earned on this investment, the Commission will permit the Company to earn a double return on its investment. Accordingly, in the alternative, the Commission should remove from rate base the $31,368,045 adjustment for BCC proposed by the Company for its Utah operations.

VIII. AFFILIATE TRANSACTIONS MANUAL

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS FOR THE COMMISSION CONCERNING THE COMPANY'S RELATIONSHIP WITH ITS AFFILIATES?

A. Yes. I recommend that the Commission order the Company to develop an affiliate transaction/cost allocation manual that depicts the methodology used to charge costs between PacifiCorp and its affiliates. This would include charges from PacifiCorp to its affiliates and charges from affiliates to PacifiCorp. While the Company has been cooperative in providing responses to discovery and answering questions about its pricing policy, a manual which codifies the Company's methodology would be extremely useful to its regulators.

Although the Company does prepare and provide to the Commission the Affiliated Interest Report required by the Oregon Commission, and this document does provide useful information, additional information is necessary to gain a complete understanding of the Company's affiliate charging methods. To the best of my knowledge, the Company does not prepare a cost allocation manual that can be used by employees or regulators when examining affiliate relationships. (Response to CCS Data Request 4.14[4].)

There are several significant pieces of information that would be useful to an understanding of the Company's transactions with its affiliates that are not contained in the Affiliated Interest Report. For example, the Affiliated Interest Report does not explain how costs are allocated or charged in any detail. The Affiliated Interest Transaction Summary, which provides a brief description of the basis to determine prices, is cryptic at best. With one exception, in every instance where PacifiCorp provides a service to an affiliate, the basis used to determine the pricing is stated as follows: "Costs incurred by PacifiCorp on behalf of subsidiaries are charged at direct cost. Labor is charged at PacifiCorp's fully loaded cost plus administrative and general expense." (2004 Affiliated Interest Report.)

[4] In response to CCS Data Request 4.14 the Company did provide a CBS Service Pricing Document, but it is not a cost allocation manual that describes methodology and policies and procedures.

There is very little discussion in the report which describes the management fee allocation, the CBS Assessments, or the direct charging methods used by the Company to assign costs to its affiliates. Furthermore, there is no discussion of how the management fee is developed, what cost centers are included in the management fee, or how the allocation factors used to allocate the management fee are developed. An examination of CCS Exhibit 3.7 gives an indication of the many adjustments made to the data to develop the foundation of the allocation factors. Other than the footnotes provided on the exhibit, there is no explanation as to the reason for the many adjustments made to the raw data. This is the type of information that could be included in a cost allocation manual with a detailed explanation as to the rationale for the various adjustments.

There is no information contained in the Affiliated Interest Report on how common plant costs are recovered from affiliates, or what return is used to charge affiliates for the investment in common plant facilities. In fact, in response to CCS Data Request 31.10, when asked to explain how general plant is allocated, including identification of the cost of equity used to charge a return on general plant charged to affiliates, the Company responded: “The Cost Center costs that are allocated to affiliates via service pricing include the depreciation associated with the Cost Center’s general plant. FY 2005 depreciation is utilized to project these costs in the test year” (Response to CCS Data Request 31.10.) The Company’s response does not explain how the return is charged on general plant. In fact, the Company's response leads me to believe that no return on common plant is charged to affiliates.

The Affiliated Interest Report is specific to Oregon Statutes and it therefore omits information important to the Utah Commission. For example, when asked why Pacific Minerals, Inc./Bridger Coal Company was not included in the Affiliated Interest Report, the Company stated that it was omitted "because it does not meet OPUC requirements for disclosure." (Response to CCS Data Request 25.22.) Because of this, there was no financial information for Bridger Coal Company or Pacific Minerals, Inc. included in the 2004 Affiliated Interest Report.

The Affiliated Interest Report does not contain the agreements between PacifiCorp and its affiliates. Consequently, it would not be evident to the Commission that there are several affiliates where no service agreement exists, even though there are services provided between the companies. (Response to CCS Data Request 25.30.)

The Affiliated Interest Report does not contain a detailed discussion of the services and/or products provided by the various affiliates, nor does it include an organization chart of PacifiCorp and its affiliates. This type of information would be very helpful in gaining an understanding of the services/products provided between the different affiliates. An organization chart would provide insight into the relationship between the different affiliates.

Again, the PacifiCorp personnel were very helpful in explaining the allocation process and answering our questions during the on-site audit. Nevertheless, rather than rely on institutional knowledge for how the pricing between affiliates takes place, good business practices would dictate the development and use of a corporate affiliate transactions manual documenting all aspects of PacifiCorp's transactions with its affiliates. Therefore, I recommend that the Commission order PacifiCorp to develop such a manual for use in the next rate proceeding.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY?

A. Yes, it does.