BEFORE THE

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IDAHO PUBLIC
UTILITIES COMMISSION

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	)	**CASE NO. PAC-E-07-5**

DIRECT TESTIMONY OF TERRI CARLOCK

IDAHO PUBLIC UTILITIES COMMISSION

SEPTEMBER 28, 2007

Q. Please state your name and address for the record.

A. My name is Terri Carlock. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as the Deputy Administrator of the Utilities Division responsible for the Accounting/Audit Section.

Q. Please outline your educational background and experience.

A. I graduated from Boise State University in 1980, with B.B.A. Degrees in Accounting and Finance. I have attended various regulatory, accounting, rate of return, economics, finance and ratings programs. I chaired the National Association of Regulatory Utilities Commissioners (NARUC) Staff Subcommittee on Economics and Finance for more than 3 years. Under this subcommittee, I also chaired the Ad Hoc Committee on Diversification. I am currently the Vice-Chair of the NARUC Staff Subcommittee on Accounting and Finance. I have been a presenter for the Institute of Public Utilities at Michigan State University and for many other conferences. Since joining the Commission Staff in May 1980, I have participated in audits, performed financial analysis on various companies, and have presented testimony before this Commission on numerous occasions.

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

A. The purpose of my testimony is to discuss policy positions, the Multi-State Process, Renewable Energy Credits and present the Staff's recommendation related to the overall cost of capital for Rocky Mountain Power to be used in the revenue requirement in this case. I will address the appropriate capital structure, cost rates and the overall rate of return.

Q. Please summarize your testimony.

A. Portions of my testimony are policy related and do not have specific recommendations directly impacting the revenue requirement. I discuss Renewable Energy Credits (RECs) in my testimony, and I recommend recognizing additional REC revenues of $4,270,923 (system) that reduce the Idaho revenue requirement by $269,344. In my testimony on the overall rate of return, I am recommending a return on common equity in the range of 9.5% - 10.5% with a point estimate of 10.25%. The recommended overall weighted cost of capital is in the range of 7.889% - 8.393% with a point estimate of 8.267% to be applied to the rate base for the test year.

Q. Are you sponsoring any exhibits to accompany your testimony?

A. Yes, I am sponsoring Staff Exhibit No. 120 and Staff Exhibit No. 121 consisting of 3 schedules.

Q. Please identify the REC or green tag adjustments made by Staff in this case.

A. Staff has made two adjustments to properly reflect REC or green tag revenues. The first imputes revenue for RECs associated with major new wind projects. The second is a proforma adjustment to better reflect REC revenue credits from sales during the adjusted test period.

Q. Please explain the adjustment to impute revenues associated with major new wind projects.

A. PacifiCorp assumes that there will be RECs with the energy generated by the Wolverine Creek, Leaning Juniper, Marengo and Goodnoe Hills projects. In the Integrated Resource Plans, the Company's economic analysis uses the sale of RECs to show the economic feasibility of the wind projects for inclusion in the system resource portfolio. Staff utilized and accepted use of these REC revenues to fully accept the inclusion of these plants in rate base and all associated costs in the revenue requirement. The associated REC revenues shown on Staff Exhibit No. 120 are required to make these specific wind projects cost effective. To compute the total REC value, Staff multiplied the Company's assumed value of RECs by the generation for each project for the time period reflected during the proformed 2007 period. These revenues need to be imputed to properly reflect all the components to justify inclusion of these plants in customer rates. The total REC values for these projects are $3,445,533 (system).

Q. Please explain the proforma adjustment to better reflect REC revenue credits from sales during the adjusted test period.

A. The proforma test year adjustment reflects a known and measurable adjustment. The 2007 REC revenues through May amounts to $1,837,075 (system) while the amount booked in 2006 was $1,011,684 (system). The difference of $825,390 (system) is the conservative proforma adjustment recommended by Staff. The adjustment is conservative since REC sales in prior years were also made in the last two quarters of the year but the 2007 comparison does not include these quarters.

Q. What is the total adjustment made by Staff for REC revenue credits?

A. The total of these two adjustments is $4,270,923 (system). Both adjustments would be allocated using the system generation factor of 6.306%, resulting in a reduction of $269,344 in the Idaho revenue requirement.

Q. Have you reviewed the testimony and exhibits of Rocky Mountain Power witnesses Hadaway and Williams associated with the return components?

A. Yes. Much of the theoretical approach used by witnesses Hadaway and Williams in their testimonies and exhibits is generally the same as I have used. My judgment in some areas of application results in different outcomes.

Q. What legal standards have been established for determining a fair and reasonable rate of return?

A. The legal test of a fair rate of return for a utility company was established in the *Bluefield Water Works* decision of the United States Supreme Court and is repeated specifically in *Hope Natural Gas*.

In *Bluefield Water Works and Improvement Co. v. West Virginia Public Service Commission*, 262 U.S. 679, 692, 43 S.Ct. 675, 67 L.Ed. 1176 (1923), the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence

> in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

The Court stated in *FPC v. Hope Natural Gas Company*, 320 U.S. 591, 603, 64 S.Ct. 281, 88 L.Ed. 333 (1944):

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.
>
> ... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. (Citations omitted.)

The Supreme Court decisions in *Bluefield Water Works* and *Hope Natural Gas* have been affirmed in *In re Permian Basin Area Rate Case*, 390 U.S. 747, 88 S.Ct 1344, 20 L.Ed 2d 312 (1968), and *Duquesne Light Co.* v. *Barasch*, 488 U. S. 299, 109 S.Ct. 609, 102 L.Ed.2d. 646 (1989). The Idaho Supreme Court has also adopted the principles established in *Bluefield Water Works* and *Hope Natural Gas*. See *In re Mountain States Tel. & Tel. Co.* 76 Idaho 474, 284 P.2d 681 (1955); *General Telephone Co.* v. *IPUC*, 109 Idaho 942, 712 P.2d 643 1986); *Hayden Pines Water Company* v. *IPUC*, 122 ID 356, 834 P.2d 873 (1992).

As a result of these United States and Idaho Supreme Court decisions, three standards have evolved for determining a fair and reasonable rate of return: (1) The Financial Integrity or Credit Maintenance Standard; (2) the Capital Attraction Standard; and, (3) The Comparable Earnings Standard. If the Comparable Earnings Standard is met, the Financial Integrity or Credit Maintenance Standard and the Capital Attraction Standard will also be met, as they are an integral part of the Comparable Earnings Standard.

Q. Have you considered these standards in your recommendation?

A. Yes. These criteria have been seriously considered in the analysis upon which my recommendations are based. It is also important to recognize that the fair rate of return that allows the utility company to maintain its financial integrity and to attract capital is established assuming efficient and economic management, as specified by the Supreme Court in *Bluefield Water Works*.

Q. Please summarize the parent/subsidiary relationships for Rocky Mountain Power.

A. Rocky Mountain Power's common stock is not traded. Rocky Mountain Power is a division of PacifiCorp and PacifiCorp is a wholly owned subsidiary of MidAmerican Energy Holdings Company (MEHC). Due to this parent/subsidiary relationship there is no direct equity market data available for utility operations at Rocky Mountain Power or PacifiCorp.

Q. What approach have you used to determine the cost of equity for Rocky Mountain Power?

A. I have primarily evaluated two methods: the Discounted Cash Flow (DCF) method and the Comparable Earnings method.

Q. Please explain the Comparable Earnings method and how the cost of equity is determined using this approach.

A. The Comparable Earnings method for determining the cost of equity is based upon the premise that a given investment should earn its opportunity costs. In competitive markets, if the return earned by a firm is not equal to the return being earned on other investments of similar risk, the flow of funds will be toward those investments earning the higher returns. Therefore, for a utility to be competitive in the financial markets, it should be allowed to earn a return on equity equal to the average return earned by other firms of similar risk. The Comparable Earnings approach is supported by the

Bluefield Water Works and *Hope Natural Gas* decisions as a basis for determining those average returns.

Industrial returns tend to fluctuate with business cycles, increasing as the economy improves and decreasing as the economy declines. Utility returns are not as sensitive to fluctuations in the business cycle because the demand for utility services generally tends to be more stable and predictable. However, returns have fluctuated since 2000 when prices in the electricity markets dramatically increased. Electricity prices have not seen the dramatic spikes lately so earnings are more stabile.

Q. Please evaluate interest rate trends.

A. The prime interest rate has increased since the last PacifiCorp rate case but has decreased from 8.25% to the current rate of 7.75%. The federal funds rate and other rates have also decreased this year.

Q. Please provide the current index levels for the Dow Jones Industrial Average and the Dow Jones Utility Average.

A. The Dow Jones Industrial Average (DJIA) closed at 13,878 on September 26, 2007. The DJIA all-time high of 14,000.41 was reached on July 19, 2007. The Dow Jones Utility Average closed at 512 on September 26, 2007.

Q. Please explain the risk differentials between industrials and utilities.

A. Risk is a degree of uncertainty relative to a company. The lower risk level associated with utilities is attributable to many factors even though the difference is not as great as it used to be. Utilities continue to have limited competition for distribution of utility services within the certificated area. With limited competition for regulated services, there is less chance of losses related to pricing practices, marketing strategy and advertising policies. The competitive risks for electric utilities have changed with increasing non-utility generation, deregulation in some states, open transmission access, and changes in electricity markets. However, competitive risks are limited for Rocky Mountain utility operations. The demand for utility services is relatively stable and certain or increasing compared to that of unregulated firms and even other utility industries.

Competitive risks continue to be lower for Rocky Mountain Power and PacifiCorp than for many other electric companies primarily because of the low-cost source of power and the low retail rates compared to national averages. The risk differential between Rocky Mountain Power and PacifiCorp and other electric utilities is based on the resource mix and the cost of those resources. All resource mixes have risks specific to resources chosen. The demand for electric utility services of Rocky Mountain Power and PacifiCorp is increasing at predictable rates. This low demand risk is partially due to the low-cost power and the customer mix of the power users.

Under regulation, utilities are generally allowed to recover through rates, reasonable, prudent and justifiable cost expenditures related to regulated services. Unregulated firms have no such assurance. Utilities in general are sheltered by regulation for reasonable cost recovery risks, making the average utility less risky than the average unregulated industrial firm.

Considering all of these comparisons, I believe a reasonable return on equity attributed to Rocky Mountain Power and PacifiCorp is 10.0% - 11.0% under the Comparable Earnings method.

Q. You indicated that the Discounted Cash Flow method is utilized in your analysis. Please explain this method.

A. The Discounted Cash Flow (DCF) method is based upon the theory that (1) stocks are bought for the income they provide (i.e., both dividends and/or gains from the sale of the stock), and (2) the market price of stocks equals the discounted value of all future incomes. The discount rate, or cost of equity, equates the present value of the stream of income to the current market price of the stock. The formula to accomplish this goal is:

$$P_o = PV = \frac{D_1}{(1+k_s)^1} + \frac{D_2}{(1+k_s)^2} + \ldots + \frac{D_N}{(1+k_s)^N} + \frac{P_N}{(1+k_s)^N}$$

P_o = Current Price

D = Dividend

k_s = Capitalization Rate, Discount Rate, or Required Rate of Return

N = Latest Year Considered

The pattern of the future income stream is the key factor that must be estimated in this approach. Some simplifying assumptions for ratemaking purposes can be made without sacrificing the validity of the results. Two such assumptions are: (1) dividends per share grow at a constant rate in perpetuity and (2) prices track earnings. These assumptions lead to the simplified DCF formula, where the required return is the dividend yield plus the growth rate (g):

$$k_s = \frac{D}{P_o} + g$$

Q. Have you factored flotation costs in with your cost of capital analysis?

A. Yes, I have considered direct flotation costs in my analysis by increasing the dividend yield component of the DCF analysis. Because only direct costs should be considered, I have used a flotation factor of 4% with 2% assigned to the utility operations. This practice continues to be reasonable because all subsidiaries of MEHC should be responsible for some of the actual flotation costs. I have therefore adjusted the DCF formula to include the direct flotation costs as "df".

$$k_s = \left[\frac{D}{P_o}(1 + df)\right] + g$$

Q. What is your estimate of the current cost of capital for Rocky Mountain Power and PacifiCorp using the Discounted Cash Flow method?

A. The current cost of equity capital for Rocky Mountain Power and PacifiCorp, using the Discounted Cash Flow method with comparable companies is between 7.7% - 11.7%. Due to ongoing capital requirements, I believe a dividend yield of 4.2% with an average growth rate of 5.2% is reasonable and representative resulting in a DCF return on equity of 9.4%.

Q. How is the growth rate (g) determined?

A. The growth rate is the factor that requires the most extensive analysis in the DCF method. It is important that the growth rate used in the model be consistent with the dividend yield so that investor expectations are accurately reflected and the growth rate is not too large or too small.

I have used an expected growth rate of 4% - 6%. This expected growth rate was derived from an analysis of various historical and projected growth indicators, including growth in earnings per share, growth in cash dividends per share, growth in book value per share, growth in cash flow and the sustainable growth.

Q. What is the capital structure you have used for Rocky Mountain Power and PacifiCorp to determine the overall cost of capital?

A. I have utilized the embedded capital structure at December 31, 2007 consisting of 49.1% debt, 0.5% preferred stock and 50.4% common equity as shown on Schedule 3 of Staff Exhibit No. 120. Rocky Mountain Power witness Williams reflects this capital structure in his testimony on page 3. I have accepted the proforma capital structure recommended by Rocky Mountain Power in this case because the proforma changes are adequately known to be included as a known and measurable adjustment in this case and it represents a capital structure consistent with the rate base investment included in the Staff revenue requirement.

Q. What are the costs related to the capital structure for debt and preferred stock?

A. I have evaluated and accepted the embedded cost rates used in Williams Exhibit Nos. 7 - 10. The cost of debt is 6.26% (Staff Exhibit No. 120, Schedule 1) and the cost of preferred stock is 5.41% (Staff Exhibit No. 120, Schedule 2).

Q. You indicated the cost of common equity range for Rocky Mountain Power and PacifiCorp is 10.0% - 11.0% under the Comparable Earnings method and 7.7% - 11.7% under the Discounted Cash Flow method. What is the cost of common equity capital you are recommending?

A. The fair and reasonable cost of common equity capital I am recommending for Rocky Mountain Power and PacifiCorp is in the range of 9.5% - 10.5%. Although any point within this range is reasonable, the return on equity granted would not normally be at either extreme of the fair and reasonable range. I utilized a point estimate of 10.25% in calculating the overall rate of return for the revenue requirement.

Q. What is the basis for your point estimate being 10.25% when your range is 9.5% - 10.5%?

A. The 10.25% return on equity point estimate utilized is based on a review of market data and comparables, average risk characteristics for Rocky Mountain Power and PacifiCorp, including past and current impacts in state jurisdictions, operations and the capital structure.

Q. What is the overall weighted cost of capital you are recommending for Rocky Mountain Power and PacifiCorp?

A. I am recommending an overall weighted cost of capital in the range of 7.889% - 8.393%. For use in calculating the revenue requirement, a point estimate consisting of a return on equity of 10.25% and a resulting overall rate of return of 8.267% was utilized as shown on Schedule 3, Staff Exhibit No. 120.

Q. Have you reviewed all of the Staff recommendations in this case to evaluate if they are consistent with Revised Protocol?

A. Yes, I have and I believe all of the recommended Staff adjustments are consistent with Revised Protocol.

Q. Are there Multi-State Process (MSP) or Revised Protocol items that have influenced Staff recommendations in this case?

A. Yes. All Staff recommendations took into consideration, and were therefore influenced by, Revised Protocol to ensure they were consistent. There are items where absent the MSP process and Revised Protocol, Staff may have made different or additional adjustments.

Q. Please explain the first area where you believe differences would have likely occurred.

A. Absent the Revised Protocol, the treatment of Monsanto by Staff would have likely been different. Staff would have likely continued to treat Monsanto completely as a system customer. Staff treatment for all ancillary services where Monsanto and irrigators were given credits would have likely been treated the same as Staff proposes in this case, i.e. as system resources.

Revised Protocol allows the costs to serve these customer contracts to be completely allocated to Idaho using dynamic system allocation factors. The bill credit provisions for Monsanto are treated similar to ancillary power supply contacts where they are allocated among states on the same basis as system resources. Staff witness Lanspery proposes the Irrigation Credits be allocated the same as ancillary power supply contacts.

The credits to Monsanto and Irrigation customers are given for various ancillary services as set out in the contacts. These ancillary services provide system benefits that are dispatchable by the Company or predetermined by contract thus avoiding the need for additional resources or duplicative services if these contracts were not in place.

I am pointing out these differences to help explain the thought process as I evaluated the consistency and reasonableness of Staff's positions under Revised Protocol. The Company and all customers continue to receive system benefits from these ancillary services set forth in the contracts. A reasonable price is paid for these services based on market evaluations that are utilized throughout the PacifiCorp models and system operations. The Revised Protocol treatment allows Idaho Commissioners to establish reasonable rates for Idaho customers and it also avoids having Idaho customers pay for any incentive or economic development rates that may be established in other states. To summarize, the Revised Protocol allocation retains the benefits, assures only reasonable costs are being allocated and most of all leaves the rate decisions for Idaho customers with the Idaho Commission without negatively impacting other states.

Q. Are there additional adjustments or issues Staff would have discussed absent the Revised Protocol?

A. Yes, there are areas where Staff would have likely proposed specific regulatory treatment or adjustments absent the MSP process and Revised Protocol. These areas include the regulatory treatment and cost allocation for hydro decommissioning and abandonment; the cost prudence of resource choices in general and under Resource Portfolio Standards (RPS); and green tag revenues in addition to the adjustment discussed previously. These additional issues would not have a material revenue requirement impact if they were proposed in this case. In fact I believe the revenue requirement could have been offset by the increasing and decreasing impacts since the rate impacts from these issues are just beginning. Future rate cases and the resulting impacts are where the regulatory treatment will become more important to customers.

The MSP Standing Committee and workgroup participants are evaluating these issues. If recommended clarifications, modifications or additions to the Revised Protocol are developed; they will be presented to the various Commissions for approval. If agreement between the states is not achieved, a different process will be followed to bring issues before the Commission. Each state could have different proposals for regulatory treatment presented. Disjointed treatment in different states may have a negative impact on system planning and/or operations and would need to be evaluated at that time.

Q. If additional adjustments are not being proposed in this case, why discuss these items?

A. These items are discussed for identification purposes. It allows parties in this case that haven't been participating in the MSP workgroup process to be aware of these current and future issues to evaluate future participation levels.

Q. Please generally describe the issue associated with hydro decommissioning and abandonment.

A. The Regional Resources category in the Revised Protocol includes the Hydro-Endowment for owned hydro resources and Mid-Columbia contracts. The allocation methodology utilizes an Embedded Cost Differential (ECD) adjustment to attribute hydro benefits and costs to the region, West or East, where hydro resources originated. The calculation of the ECD when hydro projects are decommissioned or abandoned is the issue. For example, the Powerdale Hydroelectric Facility was decommissioned for economic reasons following a flood. One reason it was more economic to decommission the facility than to repair it was timing. This facility was part of a settlement agreement to decommission so there was insufficient time before the settlement date for decommissioning to allow repairs to be economic. These circumstances were discussed in Case No. PAC-E-07-4 and Order No. 30344. The discussion topic for MSP evaluation needs to focus on the intent behind the continuation of the hydro-endowment concept in Revised Protocol. The West (the original Pacific Power system) wanted to continue to receive the benefits of the low cost hydro system in the West and was willing to pay costs associated with the hydro system including relicensing costs if they were more expensive, above embedded costs. Settlements to decommission are part of the relicensing process. The intent behind the hydro-endowment along with the ECD formula needs to be evaluated to assure they remain consistent when hydro facilities are decommissioned or abandoned. This includes evaluating costs above the embedded cost. The embedded cost should be calculated for ECD comparison purposes in the hydro-endowment without marginal new resources, including wind, being added to the embedded costs. This will allow the higher costs for relicensing to follow hydro benefits.

Q. Please generally describe issues related to resource choices in general and under Resource Portfolio Standards (RPS).

A. Resource choices in general and under RPS requirements are topics being explored in the MSP Resource Choice workgroup. The workgroup is evaluating issues that may impact cost allocations. Areas of concern with workgroup participants range from no concern, to concern when different resource preferences emerge among states. Workgroup participants note that the Revised Protocol does address divergent resource portfolio standards in the event that a state chooses a higher cost resource than contained in the IRP. Some workgroup participants note that the resulting operational effects could remain a problem. In addition, the Revised Protocol language may not cover scenarios where a state did not choose a different resource but rejected a resource in the Integrated Resource Plan or Request for Proposal. The workgroup is ongoing.

Q. What Renewable Energy Credit or Green Tag issues are being discussed within MSP?

A. As Renewable Portfolio Standards are established in numerous states, the availability of renewable resources and/or Renewable Energy Credits, RECs, to meet those requirements becomes an issue. RECs or Green Tags are tradable commodities even though the market isn't very liquid. Most terms and conditions associated with REC transactions are established in bilateral contracts. RECs represent the environmental "green" attributes associated with the generation of one megawatt-hour of renewable energy from an eligible renewable resource. Since the state RPS requirements differ, the need and regulatory treatment may not be consistent even between states with RPS requirements.

In states where RPS requirements have not been established, such as Idaho, the issue is slightly different. Meeting RPS requirements means that RECs will not be sold in the same manner as they were previously sold and the associated revenue credit dollars to Idaho will most likely decline. Available RECs will only be sold when they are not needed to meet RPS requirements. An allocation methodology is needed to provide revenue credits to states that have available RECs allocated to it and charge states for the transfer of needed RECs. This is one way to maintain or enhance the revenue stream associated with RECs in states where RPS requirements haven't been established and provide a win-win scenario for all customers.

Another issue deals with the actual revenue credits from the sale of RECs. Unless the allocation of REC sales revenue is changed to be more closely aligned with the states that have RECs available for sale, the revenue credits will go to all customers in the system rather than customers in states with available RECs. These are issues also being discussed within the ongoing MSP and workgroup meetings.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

Imputed Revenue for Green Tags Associated with Major new Wind Projects

Project Name	In-Service Date	No. Months Operational in Test Year		Imputed System Revenue
Wolverine Creek	12/1/2005	12	$	875,000
Leaning Juniper	8/1/2006	12	$	1,527,365
Marengo	8/1/2007	5	$	791,508
Goodnoe Hills	12/1/2007	1	$	251,660
Total			$	3,445,533

Exhibit No. 120
Case No. PAC-E-07-5
T. Carlock, Staff
9/28/07 Schedule

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary
December 31, 2007

LINE NO.	DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	YTM	LINE NO.
1											1
2	**Total First Mortgage Bonds**	**$3,784,835,000**	**($34,537,272)**	**($38,145,597)**	**$3,712,152,131**	**$247,986,033**	**6.33%**	**6.55%**	**21.8**	**16.0**	2
3											3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$400,470,000	($10,560,810)	($9,550,194)	$380,358,996	$18,967,516	4.39%	4.74%	28.0	13.5	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$16,046,592	4.51%	4.75%	27.8	10.2	5
6	**Total Pollution Control Revenue Bonds**	**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**	**$35,014,109**	**4.45%**	**4.74%**	**27.9**	**12.0**	6
7											7
8	**Total Cost of Long Term Debt**	**$4,523,205,000**	**($49,392,314)**	**($55,317,020)**	**$4,418,495,666**	**$283,000,142**	**6.02%**	**6.26%**	**22.8**	**15.3**	8
9											9

PACIFICORP
Electric Operations
Proforma Cost of Long-Term Debt Detail
December 31, 2007

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	YTM	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1															1
2		**First Mortgage Bonds**													2
3	8.271%	C-U Series due thru Oct 2010	04/15/92	10/01/10	18	2	$48,972,000	$13,200,000	$0	$0	$13,200,000	$100.000	8.271%	$1,091,772	3
4	7.978%	C-U Series due thru Oct 2011	04/15/92	10/01/11	18	2	$4,422,000	$1,469,000	$0	$0	$1,469,000	$100.000	7.978%	$117,197	4
5	8.493%	C-U Series due thru Oct 2012	04/15/92	10/01/12	19	3	$19,772,000	$7,988,000	$0	$0	$7,988,000	$100.000	8.493%	$678,421	5
6	8.797%	C-U Series due thru Oct 2013	04/15/92	10/01/13	19	3	$16,203,000	$7,542,000	$0	$0	$7,542,000	$100.000	8.797%	$663,470	6
7	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	20	4	$28,218,000	$14,492,000	$0	$0	$14,492,000	$100.000	8.734%	$1,265,731	7
8	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	20	5	$46,946,000	$25,697,000	$0	$0	$25,697,000	$100.000	8.294%	$2,131,309	8
9	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	21	5	$18,750,000	$11,159,000	$0	$0	$11,159,000	$100.000	8.635%	$963,580	9
10	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	22	6	$19,609,000	$12,288,000	$0	$0	$12,288,000	$100.000	8.470%	$1,040,794	10
11	**8.475%**	**Subtotal - Amortizing FMBs**			**20**	**4**		**$93,835,000**	**$0**	**$0**	**$93,835,000**		**8.475%**	**$7,952,273**	11
12															12
13	4.300%	Series due Sep 2008	09/08/03	09/15/08	5	1	$200,000,000	$200,000,000	($1,610,660)	($5,967,819)	$192,421,521	$96.211	5.167%	$10,334,000	13
14	6.900%	Series due Nov 2011	11/21/01	11/15/11	10	4	$500,000,000	$500,000,000	($5,338,849)	$0	$494,661,151	$98.932	7.051%	$35,255,000	14
15	5.450%	Series due Sep 2013	09/08/03	09/15/13	10	6	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	$96.189	5.961%	$11,922,000	15
16	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	7	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	16
17	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	24	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	17
18	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	27	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	18
19	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	27	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	19
20	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	29	$350,000,000	$350,000,000	($3,935,488)	$0	$346,064,512	$98.876	6.183%	$21,640,500	20
21	5.750%	Series due Aug 2036	03/14/07	04/01/37	30	29	$600,000,000	$600,000,000	($774,000)	$0	$599,226,000	$99.871	5.759%	$34,554,000	21
22	**5.979%**	**Subtotal - Bullet FMBs**			**22**	**19**		**$2,850,000,000**	**($25,791,718)**	**($13,231,634)**	**$2,810,976,648**		**6.154%**	**$175,401,500**	22
23															23
24	9.150%	Series C due Aug 2011	08/09/91	08/09/11	20	4	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	$99.058	9.254%	$740,320	24
25	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	4	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	$99.339	9.022%	$1,804,400	25
26	8.920%	Series C due Sep 2011	08/16/91	09/01/11	20	4	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	$99.058	9.022%	$1,804,400	26
27	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	4	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	$99.298	9.026%	$2,256,500	27
28	8.290%	Series C due Dec 2011	12/31/91	12/30/11	20	4	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	$85.539	9.972%	$299,160	28
29	8.260%	Series C due Jan 2012	01/09/92	01/10/12	20	4	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	$85.542	9.938%	$99,380	29
30	8.280%	Series C due Jan 2012	01/10/92	01/10/12	20	4	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	$85.642	9.947%	$198,940	30
31	8.250%	Series C due Feb 2012	01/15/92	02/01/12	20	4	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	$85.542	9.925%	$297,750	31
32	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	14	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	32
33	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	14	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	33
34	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	14	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	34
35	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	14	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	35
36	**8.766%**	**Subtotal - Series C MTNs**			**23**	**6**		**$111,000,000**	**($855,533)**	**($5,203,268)**	**$104,941,200**		**9.354%**	**$10,383,170**	36
37															37
38	8.130%	Series E due Jan 2013	01/20/93	01/22/13	20	5	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	$92.525	8.939%	$893,900	38
39	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	15	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	39
40	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	15	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	40
41	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	15	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	41
42	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	15	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	42
43	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	15	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	43
44	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	15	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	44
45	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	15	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	45
46	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	15	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	46
47	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	15	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	47
48	**8.100%**	**Subtotal - Series E MTNs**			**29**	**14**		**$165,000,000**	**($1,303,552)**	**($16,835,712)**	**$146,860,736**		**9.194%**	**$15,169,820**	48
49															49
50	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	16	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	50
51	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	16	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	51
52	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	16	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	52
53	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	16	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	53

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PACIFICORP
Electric Operations
Proforma Cost of Long-Term Debt Detail
December 31, 2007

LINE NO.	INTEREST RATE (a)	DESCRIPTION (b)	ISSUANCE DATE (c)	MATURITY DATE (d)	ORIG LIFE (e)	YTM (f)	PRINCIPAL AMOUNT ORIGINAL ISSUE (g)	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING (h)	ISSUANCE EXPENSES (i)	REDEMPTION EXPENSES (j)	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT (k)	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT (l)	MONEY TO COMPANY (m)	ANNUAL DEBT SERVICE COST (n)	LINE NO.
54	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	16	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	54
55	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	16	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	55
56	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	16	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	56
57	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	16	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	57
58	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	16	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	58
59	6.750%	Series F due Oct 2023	10/23/93	10/23/23	30	16	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	59
60	**7.044%**	**Subtotal - Series F MTNs**			30	16		$140,000,000	($1,193,670)	($2,874,983)	$135,931,347		7.291%	$10,208,020	60
61															61
62	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	18	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	62
63	**6.710%**	**Subtotal - Series G MTNs**			30	18		$100,000,000	($904,467)	$0	$99,095,533		6.781%	$6,781,000	63
64															64
65	6.375%	Series H due May 2008	05/12/98	05/15/08	10	0	$200,000,000	$200,000,000	($2,060,179)	$0	$197,939,821	$98.970	6.517%	$13,034,000	65
66	7.000%	Series H due Jul 2009	07/15/97	07/15/09	12	2	$125,000,000	$125,000,000	($2,428,154)	$0	$122,571,846	$98.057	7.245%	$9,056,250	66
67	**6.615%**	**Subtotal - Series H MTNs**			11	1		$325,000,000	($4,488,333)	$0	$320,511,667		6.797%	$22,090,250	67
68															68
69	**6.328%**	**Total First Mortgage Bonds**			22	16		$3,784,835,000	($34,537,272)	($38,145,597)	$3,712,152,131		6.552%	$247,986,033	69
70															70
71		**Pollution Control Revenue Bonds**													71
72	4.117%	Moffat 94 due May 2013	11/17/94	05/01/13	18	5	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	$97.666	4.302%	$1,748,978	72
73	4.002%	Converse 88 due Jan 2014	01/14/88	01/01/14	26	6	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.280%	$727,600	73
74	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	7	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	74
75	3.643%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	8	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	4.123%	$1,855,350	75
76	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	9	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.447%	$377,995	76
77	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	14	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.538%	$542,654	77
78	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	16	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.502%	$3,023,430	78
79	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	16	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.607%	$1,083,548	79
80	4.117%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	17	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	4.286%	$401,384	80
81	4.087%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	17	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	4.303%	$352,416	81
82	4.222%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	17	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	4.483%	$5,466,570	82
83	4.190%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	17	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	4.392%	$661,435	83
84	4.087%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	17	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	4.255%	$904,613	84
85	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	18	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	85
86	4.324%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	18	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.435%	$975,700	86
87	**4.395%**	**Subtotal - Secured PCRBs**			28	14		$400,470,000	($10,560,810)	($9,550,194)	$380,358,996		4.736%	$18,967,516	87
88															88
89	4.576%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	6	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	4.858%	$558,670	89
90	4.446%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	8	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	4.586%	$3,210,200	90
91	4.502%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	8	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	5.055%	$2,274,750	91
92	4.425%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	9	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	4.589%	$2,294,500	92
93	4.576%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	10	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	4.771%	$2,146,950	93
94	4.466%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	10	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	4.671%	$1,924,452	94
95	4.121%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	13	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	4.270%	$960,110	95
96	4.121%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	13	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	4.321%	$403,365	96
97	4.121%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	13	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	4.367%	$275,339	97
98	4.603%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	18	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	4.772%	$1,164,368	98
99	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	23	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.579%	$833,888	99
100	**4.513%**	**Subtotal - Unsecured PCRBs**			28	10		$337,900,000	($4,294,232)	($7,621,229)	$325,984,539		4.749%	$16,046,592	100
101															101
102	**4.449%**	**Total PCRB Obligations**			28	12		$738,370,000	($14,855,042)	($17,171,423)	$706,343,535		4.742%	$35,014,109	102
103															103
104	**6.022%**	**Total Long-Term Debt**			23	15		$4,523,205,000	($49,392,314)	($55,317,020)	$4,418,495,666		6.257%	$283,000,142	104
105															105

Exhibit No. 121
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PACIFICORP
Electric Operations
Pro Forma Cost of Preferred Stock
December 31, 2007

Line No.	Description of Issue (1)	Issuance Date (2)	Call Price (3)	Annual Dividend Rate (4)	Shares O/S (5)	Total Par or Stated Value O/S (6)	Net Premium & (Expense) (7)	Net Proceeds to Company (8)	% of Gross Proceeds (9)	Cost of Money (10)	Annual Cost (11)	Line No.
1	**5% Preferred Stock, $100 Par Value**	(a)	110.00%	5.00%	126,243	$12,624,300	($98,049)	$12,526,251	99.2%	5.04%	$636,156	1
2												2
3	**Serial Preferred, $100 Par Value**											3
4	4.52% Series	Oct-55	103.50%	4.52%	2,065	$206,500	($9,676)	$196,824	95.3%	4.74%	$9,793	4
5	7.00% Series	(b)	None	7.00%	18,046	$1,804,600	(c)	$1,804,600	100.0%	7.00%	$126,322	5
6	6.00% Series	(b)	None	6.00%	5,930	$593,000	(c)	$593,000	100.0%	6.00%	$35,580	6
7	5.00% Series	(b)	100.00%	5.00%	41,908	$4,190,800	(c)	$4,190,800	100.0%	5.00%	$209,540	7
8	5.40% Series	(b)	101.00%	5.40%	65,959	$6,595,900	(c)	$6,595,900	100.0%	5.40%	$356,179	8
9	4.72% Series	Aug-63	103.50%	4.72%	69,890	$6,989,000	($30,349)	$6,958,651	99.6%	4.74%	$331,320	9
10	4.56% Series	Feb-65	102.34%	4.56%	84,592	$8,459,200	($49,071)	$8,410,129	99.4%	4.59%	$387,990	10
11												11
12		May-95	(d)								$67,955	12
13		Oct-95	(e)								$84,019	13
14												14
15	**Total Cost of Preferred Stock**			5.026%	414,633	$41,463,300	($187,146)	$41,276,155		5.41%	$2,244,853	15
16												16
17												17

18 (a) Issue replaced 6% and 7% preferred stock of Pacific Power & Light Company and Northwestern Electric Company 18
19 and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's. 19
20 (b) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co. 20
21 (c) Original issue expense/premium has been fully amortized or expensed. 21
22 (d) Column 11 is the after-tax annual amortization of expenses related to the 8.375% QUIDS due 6/30/35 which were redeemed 11/20/00. 22
23 (e) Column 11 is the annual amortization of expenses related to the 8.55% QUIDS due 12/31/25 which were redeemed 11/20/00. 23
24 24

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Rocky Mountain Power
A division of PacifiCorp

Overall Cost of Capital

Component	Ratio	Cost	Weighted Average
Long Term Debt	49.1%	6.26%	3.074%
Preferred Stock	0.5%	5.41%	0.027%
Common Equity	50.4%	10.25%	5.166%
	100.0%		8.267%

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T. Carlock, Staff
9/28/07 Schedule 3

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 28TH DAY OF SEPTEMBER 2007, SERVED THE FOREGOING **DIRECT TESTIMONY OF TERRI CARLOCK,** IN CASE NO. PAC-E-07-05, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

JUSTIN BROWN
ROCKY MOUNTAIN POWER
201 S MAIN ST STE 2300
SALT LAKE CITY UT 84111
E-MAIL: justin.brown@pacificorp.com

BRIAN DICKMAN
MANAGER, ID REGULATORY AFFAIRS
ROCKY MOUNTAIN POWER
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