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IDAHO PUBLIC
UTILITIES COMMISSIO

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-10-07**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Direct Testimony of Bruce N. Williams**
ELECTRIC SERVICE SCHEDULES	)	
AND A PRICE INCREASE OF $27.7	)	
MILLION, OR APPROXIMATELY	)	
13.7 PERCENT	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-10-07

May 2010

1 **Q. Please state your name, business address and present position with Rocky**
2 **Mountain Power (the Company), a division of PacifiCorp.**
3 A. My name is Bruce N. Williams. My business address is 825 NE Multnomah,
4 Suite 1900, Portland, Oregon 97232. I am the Vice President and Treasurer of
5 PacifiCorp.
6 **Qualifications**
7 **Q. Briefly describe your educational and professional background.**
8 A. I received a Bachelor of Science degree in Business Administration with a
9 concentration in Finance from Oregon State University in June 1980. I also
10 received the Chartered Financial Analyst designation upon passing the
11 examination in September 1986. I have been employed by the Company for 24
12 years. My business experience has included financing of the Company's electric
13 operations and non-utility activities, responsibility for the investment
14 management of the Company's qualified and non-qualified retirement plan assets,
15 and investor relations.
16 **Q. What are your responsibilities as Vice President and Treasurer?**
17 A. I am responsible for the Company's treasury, credit risk management, pension
18 and other investment management activities. In this proceeding, I am responsible
19 for the preparation of Rocky Mountain Power's embedded cost of debt and
20 preferred equity and the testimony related to capital structure.
21 **Purpose of Testimony**
22 **Q. What is the purpose of your testimony in this proceeding?**
23 A. I will first present a financing overview of the Company. Next, I will discuss the

planned amounts of common equity, debt, and preferred stock to be included in the Company's planned capital structure. I will then analyze the embedded cost of debt and preferred stock supporting Rocky Mountain Power's electric operations in the state of Idaho for the test period. This analysis includes the use of forward interest rates, historical relationship of security trading patterns, and known and measurable changes to the debt and preferred stock portfolios.

Q. What time period does your analyses cover?

A. The test period in this proceeding is the twelve months ending December 31, 2009, with known and measurable changes through December 2010. The capital structure and cost of debt and preferred stock applied in this case were determined using an average of the five quarter ending balances from the quarter ending December 31, 2009, through the quarter ending December 31, 2010.

Q. What is the overall cost of capital that you are proposing in this proceeding?

A. Rocky Mountain Power is proposing an overall cost of capital of 8.36 percent. This cost includes the Return on Equity recommendation from Dr. Samuel C. Hadaway and the following capital structure and costs:

Component	Percent of Total	% Cost	Weighted Average
Long Term Debt	47.6%	5.92%	2.82%
Preferred Stock	0.3%	5.41%	0.02%
Common Stock Equity	52.1%	10.60%	5.52%
Total	100.0%		8.36%

Financing Overview

Q. Please explain the Company's requirements to generate new capital.

A. As described in Company witness Mr. A. Richard Walje's direct testimony, the Company continues to make ongoing investment in infrastructure including

1 investment in generation, transmission and distribution. These and future capital
2 additions and investments will require the Company to raise funds by issuing
3 significant amounts of new long-term debt in the capital markets and obtaining
4 new capital contributions from its parent company. Funds will also be made
5 available by the continued absence of any dividends or distributions by
6 PacifiCorp to its parent company during the period. Since the acquisition of
7 PacifiCorp by MidAmerican Energy Holdings Company ("MEHC") in March
8 2006, there have been no common stock dividends or distributions, PacifiCorp
9 has received $990 million in additional cash equity contributions from MEHC,
10 and $1.7 billion of earnings have been retained in PacifiCorp. These actions help
11 ensure that PacifiCorp remains well-positioned to support the additional
12 investments that have been and will continue to be made in the system.
13 **Q. How does the Company finance its electric utility operations?**
14 A. The Company finances its regulated utility operations utilizing a blend of debt and
15 common equity capital. Immediately prior to and during periods of significant
16 capital expenditures such as the current situation, the Company's requirement for
17 more common equity as a component of the capital structure will increase. This
18 provides more flexibility regarding the type and timing of debt financing, better
19 access to the capital markets, a more competitive cost of debt, and over the long-
20 run, more stable credit ratings; all of which assist in financing such expenditures.
21 In fact, the Company's equity component is expected to remain in excess of 50
22 percent for the next several years to facilitate the financings necessary for the
23 investments in system reliability and infrastructure.

1 In addition, all else being equal, the Company will need to have a greater
2 common equity component to offset various adjustments that rating agencies
3 make to the debt component of the Company's published financial statements. I
4 will discuss these adjustments in greater detail later in this testimony.

5 **Q. Do you believe the proposed capital structure is a reasonable capital**
6 **structure for the purpose of setting rates in this Cocket?**

A. Yes. While the capital structure will vary due to financing activity and capital expenditures, I believe the proposed capital structure to be a fair and reasonable reflection of the structure.

7 **Q. What types of securities does the Company employ in the long-term debt and**
8 **preferred stock components of its capital structure?**

9 A. The Company relies on a mix of first mortgage bonds, other secured debt, tax-
10 exempt debt, unsecured debt and preferred stock to meet its long-term financing
11 requirements. These securities employ various maturities in order to provide
12 flexibility and mitigate refinancing risks.

13 The Company has completed the majority of its long-term financing
14 utilizing secured first mortgage bonds issued under the Mortgage Indenture dated
15 January 9, 1989. Exhibit No. 5 shows that, for the twelve months ending
16 December 31, 2010, the Company is projected to have approximately $5.6 billion
17 of first mortgage bonds outstanding, with an average cost of 6.38 percent.
18 Presently, all outstanding first mortgage bonds bear interest at fixed rates.
19 Proceeds from the issuance of the first mortgage bonds (and other financing
20 instruments) are used to finance the combined utility operation.

1 Another important source of financing has been the tax-exempt financing
2 associated with certain qualifying equipment at power generation plants. Under
3 arrangements with local counties and other tax-exempt entities, the Company
4 borrows the proceeds and guarantees the repayment of the long-term debt in order
5 to take advantage of their tax-exempt status in financings. During the twelve
6 months ending December 31, 2010, the Company's tax-exempt portfolio is
7 projected to be $738 million in principal amount with an average cost of 2.44
8 percent (including the cost of issuance and credit enhancement.)

9 **Planned Capital Structure**

10 **Q. How did you determine the capital structure proposed in this proceeding?**

11 A. The Company used an average of the five quarter ending balances during the time
12 period ending December 31, 2010, to calculate its proposed capital structure.
13 This approach smoothes volatility in the capital structure which will fluctuate as
14 the Company expends capital, issues or retires debt, retains earnings and receives
15 infusions of new equity.

16 **Q. How does the Company determine the amount of common equity, long-term**
17 **debt, and preferred stock to be included in its planned capital structure?**

18 A. As a regulated utility, Rocky Mountain Power has a duty and an obligation to
19 provide safe, adequate and reliable service to customers while balancing cost and
20 risk. Significant capital expenditures for new generation, transmission and
21 distribution plant investment, operating and maintenance costs for new and
22 existing utility plant assets, and clean air investments are required for Rocky
23 Mountain Power to fulfill this obligation. Through its planning process, the

1 Company determined the amount of necessary new financing including capital
2 contributions needed to support these activities and calculated the required equity
3 and debt ratios required to maintain continued access to the financial markets.

4 **Q. Has the Company previously received capital contributions from MEHC and**
5 **does it expect future contributions as well?**

6 A. Yes. Since the acquisition by MEHC on March 21, 2006, the Company has
7 received a total of $990 million of cash capital contributions from MEHC via its
8 direct parent company, PPW Holdings, LLC. The Company expects additional
9 cash equity contributions of $100 million before the end of 2010.

10 **Q. Why is there the need for additional amounts of equity?**

11 A. The Company's capital structure reflects the cost increases described in this case,
12 including investment in infrastructure and power costs. These cost increases,
13 coupled with the credit rating agencies' expectations for credit metrics and
14 balance sheet strength, mean that the Company cannot finance itself solely with
15 new debt. Additional equity is required along with improved business results and
16 other considerations to support PacifiCorp's current senior secured 'A' credit
17 rating from Standard & Poor's ("S&P"), 'A2' rating from Moody's Investors
18 Service ("Moody's"), and 'A-'from Fitch Ratings.

19 **Q. Please describe the changes to the amount of outstanding long-term debt.**

20 A. During the period ending December 31, 2010, the balance of the outstanding
21 long-term debt will change through maturities and principal amortization. Based
22 upon the long-term debt series outstanding at December 31, 2009, I have
23 calculated the reduction to the outstanding balances for maturities and principal

1 amortizations totaling $14.6 million that are scheduled to occur during the period
2 ending December 31, 2010.

3 **Q. Is the proposed capital structure consistent with the Company's current**
4 **credit rating?**

5 A. Yes. This capital structure is intended to enable the Company to deliver its
6 required capital expenditures while achieving credit ratios that are expected to
7 support the continuance of PacifiCorp's current credit ratings.

8 **Q. How does maintenance of a strong credit rating benefit customers?**

9 A. The credit rating given to a utility has a direct impact on the price that a utility
10 pays to attract the capital necessary to support its current and future operating
11 needs. A solid credit rating directly benefits customers by reducing immediate
12 and future borrowing costs related to the financing needed to support regulatory
13 operations.

14 **Q. Are there other benefits?**

15 A. Yes. During periods of capital market disruptions, higher-rated companies are
16 more likely to have ongoing, uninterrupted access to capital and access at lower
17 costs. This is not always the case with lower-rated companies, which find
18 themselves either unable to secure capital or able to secure capital only on
19 unfavorable terms and conditions during such periods.

20 In addition, higher-rated companies have greater access to the long-term
21 markets for power purchases and sales. Such access provides these companies
22 with more alternatives when attempting to meet the current and future load
23 requirements of their customers.

1 Finally, a company with strong ratings will often avoid having to meet
2 costly collateral requirements that are typically imposed on lower-rated
3 companies when securing power in these markets.

4 **Q. Did S&P and Moody's change the Company's credit ratings in 2009?**

5 A. Yes. S&P upgraded PacifiCorp's senior secured debt to 'A' while it downgraded
6 PacifiCorp's short-term debt rating to 'A-2'. Similarly, Moody's upgraded
7 PacifiCorp's senior secured debt to 'A2'.

8 **Q. Please explain these rating changes.**

9 A. The upgrade to PacifiCorp's senior secured debt merely reflects a change in
10 S&P's methodology rather than a change in PacifiCorp's credit quality or
11 financial metrics. S&P changed its approach to estimating the amount of
12 collateral available to senior secured debt holders in the event of a default by
13 PacifiCorp on its first mortgage bonds.

14 S&P continues to be cautious about PacifiCorp's credit metrics and has
15 stated it views the Company's credit metrics on a stand-alone basis as more
16 consistent with a 'BBB' rating. Indeed, in downgrading the Company's short-
17 term debt rating, S&P cited a need to take a firmer view on linking PacifiCorp
18 short-term ratings to stand-alone credit quality. S&P sustained its current 'A-'
19 corporate credit rating based on its expectation "that management will achieve
20 cash flow metrics more consistent with an 'A' rating over the next several years."[1]

21 Moody's upgrade of PacifiCorp's senior debt was part of an industry-wide
22 action in which the majority of senior secured debt ratings of investment-grade

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[1] Standard & Poor's RatingsDirect April 1, 2009, and reiterated in the RatingsDirect of April 30, 2010.

1 regulated utilities were upgraded by one level. The action was a result of an
2 analysis of the history of regulated utility defaults and was not specific or unique
3 to the Company.

4 **Q. Do these rating agency actions change the Company's need to add equity to**
5 **its capital structure and improve its financial metrics?**

6 A. No. Without continued improvement in financial metrics along with supportive
7 state regulatory outcomes in rate cases, the ratings direction is likely to be lower
8 rather than higher for PacifiCorp.

9 **Q. Do S&P's recent credit reports on PacifiCorp underline S&P's expectation**
10 **that PacifiCorp improve its financial metrics in order to maintain its current**
11 **credit rating?**

12 A. Yes. In its latest report, S&P made several references to the need for PacifiCorp
13 to improve its stand-alone financial metrics, noting that PacifiCorp had an
14 "aggressive financial risk profile that reflects a large capital program and the need
15 to shore up cash flow metrics." S&P also stated that "[G]iven the recent turmoil
16 in both the liquidity and capital markets, we have taken a firmer view on the need
17 to link the PacifiCorp short-term ratings to its stand-alone credit quality, which
18 supports an 'A-2' short-term rating."[2] S&P also reiterated its credit views,
19 including that "supportive rate case outcomes remain key to maintaining and
20 improving upon the Company's financial performance."[3] Exhibit No. 6 is the
21 April 30, 2010 S&P RatingsDirect publication.

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[2] Standard & Poor's RatingsDirect April 30, 2010
[3] *Id.*

1 **Purchase Power Agreements**

2 **Q. Is the Company subject to rating agency debt imputation associated with**

3 **Purchase Power Agreements?**

4 A. Yes. Rating agencies and financial analysts consider purchase power agreements

5 ("PPAs") to be debt-like and will impute debt and related interest when

6 calculating financial ratios. For example, S&P will adjust the Company's

7 published financial results and impute debt balances and interest expense resulting

8 from PPAs when assessing creditworthiness. It does so in order to obtain a more

9 accurate assessment of a company's financial commitments and fixed payments.

10 Exhibit No. 7 is the May 7, 2007, publication by S&P detailing its view of the

11 debt aspects of PPAs.

12 **Q. How does this impact the Company?**

13 A. In its April 30, 2010, RatingsDirect report cited above, S&P stated that

14 approximately $395 million of additional debt and related interest expense were

15 added to the Company's debt and coverage tests solely as a result of PPAs. There

16 were also other adjustments made by S&P that together resulted in total

17 imputations of approximately $1 billion of debt and $78 million of interest being

18 added into the calculation of PacifiCorp's credit ratios. These adjustments are

19 detailed by S&P in its April 30, 2010, Ratings Direct report (Exhibit No. 6)

20 **Q. How would the inclusion of this PPA-related debt affect the Company's**

21 **capital structure?**

22 A. Negatively. By including the imputed debt resulting from PPAs and these other

23 adjustments, the Company's capital structure has a lower equity component as a

1 corollary to the higher debt component, lower coverage ratios and reduced
2 financial flexibility than what might otherwise appear to be the case from a
3 review of the book value capital structure. For example, if one were to add the $1
4 billion of debt adjustments that S&P makes to the Company's capital structure in
5 this case, the resulting common equity percentage would decline from 52.1
6 percent to 48.5 percent. The table below shows the proposed capital structure and
7 how the S&P adjustments impact the components when viewed by the rating
8 agency.

Illustration of Rating Agency Adjustments to PacifiCorp's Capital Structure ($ in millions)			
	Book Values / Ratios	Rating Agency Adjustments	Adjusted Book Values / Ratios
Long-Term Debt	6,369/47.6%	$1,000	7,369/51.2%
Preferred Stock	41/0.3%	0	41/0.3%
Common Equity	6,984/52.1%	0	6,984/48.5%
Totals	$13,394/100.0%	$1,000	$14,394/100.0%

9 **Financing Cost Calculations**

10 **Q. How did you calculate the Company's embedded costs of long-term debt and**
11 **preferred stock?**

12 A. I calculated the embedded costs of debt and preferred stock using the
13 methodology relied upon in the Company's previous rate cases in Idaho and other
14 jurisdictions.

15 **Q. Please explain the cost of debt calculation.**

16 A. I calculated the cost of debt by issue, based on each debt series' interest rate and
17 net proceeds at the issuance date, to produce a bond yield to maturity for each

1 series of debt. It should be noted that in the event a bond was issued to refinance
2 a higher cost bond, the pre-tax premium and unamortized costs, if any, associated
3 with the refinancing were subtracted from the net proceeds of the bonds that were
4 issued. The bond yield was then multiplied by the principal amount outstanding
5 of each debt issue, resulting in an annualized cost of each debt issue. Aggregating
6 the annual cost of each debt issue produces the total annualized cost of debt.
7 Dividing the total annualized cost of debt by the net proceeds of debt outstanding
8 produces the weighted average cost for all debt issues. This is the Company's
9 embedded cost of long-term debt.
10 **Q. How did you calculate the embedded cost of preferred stock?**
11 A. The embedded cost of preferred stock was calculated by first determining the cost
12 of money for each issue. This is the result of dividing the annual dividend rate by
13 the per share net proceeds for each series of preferred stock. The cost associated
14 with each series was multiplied by the total par or stated value outstanding for
15 each issue to yield the annualized cost for each issue. The sum of annualized
16 costs for each issue produces the total annual cost for the entire preferred stock
17 portfolio. I then divided the total annual cost by the total amount of preferred
18 stock outstanding to produce the weighted average cost of all issues. This is the
19 Company's embedded cost of preferred stock.
20 **Q. A portion of the Company's debt portfolio bears variable coupon rates.**
21 **What is the basis for the projected interest rates used by the Company?**
22 A. The majority of the Company's variable rate debt is in the form of tax-exempt
23 debt. Exhibit No. 8 shows that these securities on average had been trading at

1 approximately 91 percent of the 30-day LIBOR (London Inter Bank Offer Rate)
2 for the period January 2000 through December 2009. Therefore, the Company
3 has applied a factor of 91 percent to the forward 30-day LIBOR Rates during the
4 period ending December 31, 2010, and then added the respective credit
5 enhancement and remarketing fees for each floating rate tax-exempt bond. Credit
6 enhancement and remarketing fees are included in the interest component because
7 these are costs which contribute directly to the interest rate on the securities and
8 are recognized in interest expense.

9 **Embedded Cost of Long-Term Debt**

10 **Q. What is the Company's embedded cost of long-term debt?**

11 A. The embedded cost of long-term debt is 5.92 percent as shown in Exhibit No. 5.

12 **Embedded Cost of Preferred Stock**

13 **Q. What is the Company's embedded cost of preferred stock?**

14 A. Exhibit No. 9 shows the embedded cost of preferred stock at December 31,
15 2010, to be 5.41 percent

16 **Q. Does this conclude your testimony?**

17 A. Yes.

Case No. PAC-E-10-07
Exhibit No. 5
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Cost of Long Term Debt Summary

May 2010

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary
Fiscal Year Ending December 31, 2010

LINE NO.	DESCRIPTION	AVERAGE AMOUNT OUTSTANDING*	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	LINE NO.
1										1
2	**Total First Mortgage Bonds**	**$5,631,052,600**	**($59,301,777)**	**($32,177,777)**	**$5,539,573,046**	**$358,981,736**	**6.216%**	**6.375%**	**23.5**	2
3										3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$400,470,000	($10,560,810)	($9,550,194)	$380,358,996	$12,297,544	2.773%	3.071%	28.0	4
5	Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,294,232)	($7,621,229)	$325,984,539	$5,707,761	1.522%	1.689%	27.8	5
6	**Total Pollution Control Revenue Bonds**	**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**	**$18,005,305**	**2.201%**	**2.439%**	**27.9**	6
7										7
8	**Total Cost of Long Term Debt**	**$6,369,422,600**	**($74,156,818)**	**($49,349,200)**	**$6,245,916,581**	**$376,987,041**	**5.751%**	**5.919%**	**24.0**	8
9										9
10	***average of the 5 quarter-ending balances spanning the fiscal year**									10
11										11

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail
Fiscal Year Ending December 31, 2010

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT AVERAGE 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)	(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	$48,972,000	$3,803,200	$0	$0	$3,803,200	$100.000	8.270%	$314,525	3
4	7.978%	C-U Series due thru Oct 2011	04/15/92	10/01/11	19	$4,422,000	$716,800	$0	$0	$716,800	$100.000	7.977%	$57,179	4
5	8.493%	C-U Series due thru Oct 2012	04/15/92	10/01/12	20	$19,772,000	$4,860,400	$0	$0	$4,860,400	$100.000	8.492%	$412,745	5
6	8.797%	C-U Series due thru Oct 2013	04/15/92	10/01/13	20	$16,203,000	$5,201,400	$0	$0	$5,201,400	$100.000	8.796%	$457,515	6
7	8.734%	C-U Series due thru Oct 2014	04/15/92	10/01/14	21	$28,218,000	$10,803,400	$0	$0	$10,803,400	$100.000	8.733%	$943,461	7
8	8.294%	C-U Series due thru Oct 2015	04/15/92	10/01/15	21	$46,946,000	$20,160,400	$0	$0	$20,160,400	$100.000	8.293%	$1,671,902	8
9	8.635%	C-U Series due thru Oct 2016	04/15/92	10/01/16	22	$18,750,000	$9,140,400	$0	$0	$9,140,400	$100.000	8.634%	$789,182	9
10	8.470%	C-U Series due thru Oct 2017	04/15/92	10/01/17	22	$19,609,000	$10,366,600	$0	$0	$10,366,600	$100.000	8.469%	$877,947	10
11	**8.493%**	**Subtotal - Amortizing FMBs**			**21**		**$65,052,600**	**$0**	**$0**	**$65,052,600**		**8.492%**	**$5,524,456**	11
12														12
13	6.900%	Series due Nov 2011	11/21/01	11/15/11	10	$500,000,000	$500,000,000	($5,338,849)	$0	$494,661,151	$98.932	7.051%	$35,255,000	13
14	5.450%	Series due Sep 2013	09/08/03	09/15/13	10	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	$96.189	5.960%	$11,920,000	14
15	4.950%	Series due Aug 2014	08/24/04	08/15/14	10	$200,000,000	$200,000,000	($2,170,365)	$0	$197,829,635	$98.915	5.090%	$10,180,000	15
16	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	16
17	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	17
18	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	18
19	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	$350,000,000	$350,000,000	($4,048,881)	$0	$345,951,119	$98.843	6.185%	$21,647,500	19
20	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	20
21	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	$600,000,000	$600,000,000	($5,877,281)	$0	$594,122,719	$99.020	6.323%	$37,938,000	21
22	5.650%	Series due Jul 2018	07/17/08	07/15/18	10	$500,000,000	$500,000,000	($3,971,596)	$0	$496,028,404	$99.206	5.756%	$28,780,000	22
23	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	$300,000,000	$300,000,000	($3,960,958)	$0	$296,039,042	$98.680	6.450%	$19,350,000	23
24	5.500%	Series due Jan 2019	01/08/09	01/15/19	10	$350,000,000	$350,000,000	($4,802,369)	$0	$345,197,631	$98.628	5.681%	$19,883,500	24
25	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	$650,000,000	$650,000,000	($12,298,685)	$0	$637,701,315	$98.108	6.139%	$39,903,500	25
26	**6.037%**	**Subtotal - Bullet FMBs**			**23**		**$5,050,000,000**	**($55,044,555)**	**($7,263,815)**	**$4,987,691,630**		**6.157%**	**$310,915,500**	26
27														27
28	9.150%	Series C due Aug 2011	08/09/91	08/09/11	20	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	$99.058	9.254%	$740,320	28
29	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	$99.339	9.021%	$1,804,200	29
30	8.920%	Series C due Sep 2011	08/16/91	09/01/11	20	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	$99.058	9.022%	$1,804,400	30
31	8.950%	Series C due Sep 2011	08/16/91	09/01/11	20	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	$99.298	9.026%	$2,256,500	31
32	8.290%	Series C due Dec 2011	12/31/91	12/30/11	20	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	$85.539	9.972%	$299,160	32
33	8.260%	Series C due Jan 2012	01/09/92	01/10/12	20	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	$85.542	9.938%	$99,380	33
34	8.280%	Series C due Jan 2012	01/10/92	01/10/12	20	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	$85.642	9.947%	$198,940	34
35	8.250%	Series C due Feb 2012	01/15/92	02/01/12	20	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	$85.542	9.924%	$297,720	35
36	8.530%	Series C due Dec 2021	12/16/91	12/16/21	30	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	$85.539	10.066%	$1,509,900	36
37	8.375%	Series C due Dec 2021	12/31/91	12/31/21	30	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	$85.539	9.889%	$494,450	37
38	8.260%	Series C due Jan 2022	01/08/92	01/07/22	30	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	$85.642	9.745%	$487,250	38
39	8.270%	Series C due Jan 2022	01/09/92	01/10/22	30	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	$85.542	9.768%	$390,720	39
40	**8.766%**	**Subtotal - Series C MTNs**			**23**		**$111,000,000**	**($855,533)**	**($5,203,268)**	**$104,941,200**		**9.354%**	**$10,382,940**	40
41														41
42	8.130%	Series E due Jan 2013	01/20/93	01/22/13	20	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	$92.525	8.939%	$893,900	42
43	8.050%	Series E due Sep 2022	09/18/92	09/18/22	30	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	$87.820	9.258%	$1,388,700	43
44	8.070%	Series E due Sep 2022	09/09/92	09/09/22	30	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	$87.820	9.280%	$742,400	44
45	8.110%	Series E due Sep 2022	09/11/92	09/09/22	30	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	$87.820	9.325%	$1,119,000	45
46	8.120%	Series E due Sep 2022	09/11/92	09/09/22	30	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	$87.820	9.336%	$4,668,000	46
47	8.050%	Series E due Sep 2022	09/14/92	09/14/22	30	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	$87.820	9.258%	$925,800	47
48	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	$90.953	8.953%	$2,238,250	48
49	8.080%	Series E due Oct 2022	10/15/92	10/14/22	30	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	$87.895	9.283%	$2,413,580	49
50	8.230%	Series E due Jan 2023	01/29/93	01/20/23	30	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	$99.056	8.316%	$332,640	50
51	8.230%	Series E due Jan 2023	01/20/93	01/20/23	30	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	$92.525	8.951%	$447,550	51
52	**8.100%**	**Subtotal - Series E MTNs**			**29**		**$165,000,000**	**($1,303,552)**	**($16,835,712)**	**$146,860,736**		**9.194%**	**$15,169,820**	52
53														53

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PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Detail
Fiscal Year Ending December 31, 2010

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT AVERAGE 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)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
54	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	$93.730	7.804%	$858,440	54
55	7.260%	Series F due Jul 2023	07/22/93	07/21/23	30	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	$93.730	7.804%	$2,107,080	55
56	7.230%	Series F due Aug 2023	08/16/93	08/16/23	30	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	$97.294	7.457%	$1,118,550	56
57	7.240%	Series F due Aug 2023	08/16/93	08/16/23	30	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	$97.294	7.467%	$2,240,100	57
58	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.810%	$136,200	58
59	6.720%	Series F due Sep 2023	09/14/93	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	$99.235	6.780%	$135,600	59
60	6.750%	Series F due Sep 2023	09/14/93	09/14/23	30	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	$98.552	6.865%	$343,250	60
61	6.750%	Series F due Oct 2023	10/23/93	10/26/23	30	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	$99.238	6.810%	$817,200	61
62	6.750%	Series F due Oct 2023	10/23/93	10/26/23	30	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	$99.238	6.810%	$1,089,600	62
63	6.750%	Series F due Oct 2023	10/23/93	10/26/23	30	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	$99.238	6.810%	$1,362,000	63
64	**7.044%**	**Subtotal - Series F MTNs**			**30**		**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**		**7.291%**	**$10,208,020**	64
65														65
66	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	66
67	**6.710%**	**Subtotal - Series G MTNs**			**30**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	67
68														68
69	**6.216%**	**Total First Mortgage Bonds**			**24**		**$5,631,052,600**	**($59,301,777)**	**($32,177,777)**	**$5,539,573,046**		**6.375%**	**$358,981,736**	69
70														70
71		**Pollution Control Revenue Bonds**												71
72	1.535%	Moffat 94 due May 2013	11/17/94	05/01/13	18	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	$97.666	1.682%	$683,817	72
73	4.002%	Converse 88 due Jan 2014	01/14/88	01/01/14	26	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	$95.672	4.279%	$727,430	73
74	4.002%	Sweetwater 84 due Dec 2014	12/12/84	12/01/14	30	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	$98.481	4.091%	$613,650	74
75	2.299%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	$92.555	2.711%	$1,219,950	75
76	4.229%	Forsyth 86 due Dec 2016	12/29/86	12/01/16	30	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	$96.414	4.446%	$377,910	76
77	5.745%	Lincoln 93 due Nov 2021	11/01/93	11/01/21	28	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	$89.869	6.536%	$542,488	77
78	5.770%	Emery 93A due Nov 2023	11/01/93	11/01/23	30	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	$90.394	6.500%	$3,022,500	78
79	5.745%	Emery 93B due Nov 2023	11/01/93	11/01/23	30	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	$88.813	6.604%	$1,083,056	79
80	1.437%	Carbon 94 due Nov 2024	11/17/94	11/01/24	30	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	$97.169	1.555%	$145,626	80
81	1.433%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	$96.385	1.585%	$129,812	81
82	1.431%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	$95.736	1.611%	$1,964,453	82
83	1.521%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	$96.651	1.663%	$250,448	83
84	1.421%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	$97.183	1.539%	$327,191	84
85	4.231%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	$97.509	4.381%	$232,193	85
86	4.330%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	$22,000,000	$22,000,000	($404,262)	$0	$21,595,738	$98.162	4.441%	$977,020	86
87	**2.773%**	**Subtotal - Secured PCRBs**			**28**		**$400,470,000**	**($10,560,810)**	**($9,550,194)**	**$380,358,996**		**3.071%**	**$12,297,544**	87
88														88
89	1.360%	Sweetwater 88B due Jan 2014	01/14/88	01/01/14	26	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	$95.852	1.555%	$178,825	89
90	1.336%	Sweetwater 90A due Jul 2015	07/25/90	07/01/15	25	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	$97.920	1.435%	$1,004,500	90
91	1.351%	Emery 91 due Jul 2015	05/23/91	07/01/15	24	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	$92.353	1.740%	$783,000	91
92	1.392%	Sweetwater 88A due Jan 2017	01/14/88	01/01/17	29	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	$97.391	1.504%	$752,000	92
93	1.356%	Forsyth 88 due Jan 2018	01/14/88	01/01/18	30	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	$96.903	1.484%	$667,800	93
94	1.344%	Gillette 88 due Jan 2018	01/14/88	01/01/18	30	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	$96.704	1.480%	$609,760	94
95	1.242%	Converse 92 due Dec 2020	09/29/92	12/01/20	28	$22,485,000	$22,485,000	($242,164)	($303,303)	$21,939,533	$97.574	1.346%	$302,648	95
96	1.242%	Sweetwater 92A due Dec 2020	09/29/92	12/01/20	28	$9,335,000	$9,335,000	($167,524)	($134,094)	$9,033,382	$96.769	1.381%	$128,916	96
97	1.242%	Sweetwater 92B due Dec 2020	09/29/92	12/01/20	28	$6,305,000	$6,305,000	($151,908)	($97,735)	$6,055,357	$96.041	1.413%	$89,090	97
98	1.354%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	1.465%	$357,460	98
99	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	$94.201	6.578%	$833,762	99
100	**1.522%**	**Subtotal - Unsecured PCRBs**			**28**		**$337,900,000**	**($4,294,232)**	**($7,621,229)**	**$325,984,539**		**1.689%**	**$5,707,761**	100
101														101
102	**2.201%**	**Total PCRB Obligations**			**28**		**$738,370,000**	**($14,855,042)**	**($17,171,423)**	**$706,343,535**		**2.439%**	**$18,005,305**	102
103														103
104	**5.751%**	**Total Long-Term Debt**			**24**		**$6,369,422,600**	**($74,156,818)**	**($49,349,200)**	**$6,245,916,581**		**5.919%**	**$376,987,041**	104
105														105

Rocky Mountain Power
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Case No. PAC-E-10-07
Witness: Bruce N. Williams

Case No. PAC-E-10-07
Exhibit No. 6
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct Rating Factors

May 2010

STANDARD &POOR'S

Global Credit Portal
RatingsDirect®

April 30, 2010

PacifiCorp

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Outlook

PacifiCorp

Major Rating Factors

Corporate Credit Rating
A-/Stable/A-2

Strengths:

- Market and regulatory diversity afforded by PacifiCorp's electric utility business, which serves portions of six western U.S. states;
- Retail electric rates compare favorably with those of other electric suppliers operating in the states PacifiCorp serves, suggesting that the company may be able to maintain its competitive advantage despite its ongoing need for rate relief to support a large capital program;
- The company has made progress in putting into place fuel and purchased power adjusters in the six states it serves (an adjuster was put into effect in Idaho in 2009, and one is pending in PacifiCorp's largest market, Utah);
- The completion of 1,068 megawatts of new natural gas plants, along with wind farm investment, is reducing the company's reliance on purchased power; and
- A tentative resolution in the contentious Klamath hydro relicensing case has the potential to adequately address the company's financial exposure if the project is decommissioned, as is now envisioned.

Weaknesses:

- Despite recent rate relief in nearly all states PacifiCorp serves, regulatory lag continues to allow only modest improvement in the company's financial profile: Its return on equity remains under authorized levels and although leverage has improved since MidAmerican Energy Holdings Co. (MEHC) acquired it in 2006, cash flow metrics remain weak;
- Regulators will need to consistently support retail rate increases to recover PacifiCorp's planned capital investments, although the recessionary environment has caused some scaling-back of capital plans;
- Growth in the percentage of generation provided by natural gas costs mitigates some of the company's potential exposure to carbon regulation, but introduces greater potential for cost volatility.

Rationale

The 'A-' corporate credit rating (CCR) on PacifiCorp reflects its "excellent" business risk profile, evidenced by a diverse and growing service territory, and "aggressive" financial risk profile that reflects a large capital program and the need to shore up its cash flow metrics. While the ring-fenced utility's credit metrics are more consistent on a stand-alone basis with a 'BBB' category rating, Standard & Poor's Ratings Services expects that management will achieve cash flow metrics more consistent with an 'A' category rating over the next several years. PacifiCorp is owned by MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable/--). In turn, MEHC is privately held and majority owned by Berkshire Hathaway (AA+/Stable/A-1+), which at year-end 2009 had an 89.5% interest in MEHC on an undiluted basis. (MEHC's remaining common equity is owned by Walter Scott [9.7%] and President and Chief Executive Officer Greg Abel [0.8%]). MEHC has demonstrated a willingness to deploy equity to support the utility's large capital program, providing the utility with $865 million in equity contributions since it purchased

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the company in March 2006.

MEHC's credit profile is supported by Berkshire, which has in place through February 2011 a $3.5 billion equity commitment agreement between itself and MEHC in which MEHC can unilaterally call upon Berkshire to support either its debt repayment or the capital needs of its regulated subsidiaries, including PacifiCorp. In March 2010, the agreement was amended to extend through February 2014 at a lower level of $2 billion. We view this agreement between PacifiCorp's parent and a 'AA+' rated entity as reducing the likelihood of a PacifiCorp default.

Nevertheless, we expect PacifiCorp to grow into a stand-alone credit profile consistent with the 'A-' rating on the company. We take this view because the utility has no right to cause MEHC to make an equity contribution, either from MEHC or via Berkshire through an MEHC board request. While MEHC would typically have strong incentives to support the utility by tapping the Berkshire contingent equity, we would note that in a catastrophic utility event, MEHC would be expected to do so only if doing so were in the economic best interests of the parent. Such a scenario is remote and would require an unprecedented event such as what occurred during the western energy crisis, when regulators refused to allow utilities to recover power procurement costs.

PacifiCorp serves 1.7 million customers in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho, and California. The company operates as Pacific Power in Oregon, Washington, and California, and as Rocky Mountain Power in Utah, Wyoming, and Idaho. The company's two largest markets, Utah and Oregon, accounted for about 67% of the company's retail electric sales in 2009, with Wyoming and Washington at 25%, and the balance being sold to customers in Idaho and California. As of Dec. 31, 2009, the utility's long-term debt was $6.4 billion. Consolidated long-term debt at MEHC (which includes PacifiCorp's debt) was nearly $20 billion as of the same date.

Supportive rate case outcomes remain key to maintaining and improving upon the company's financial performance. When MEHC purchased PacifiCorp in 2006 from ScottishPower, the utility had consistently been unable to earn its authorized return on equity (ROE), which varies by jurisdiction but ranges from 10% to 10.6%. Management has focused on improving its returns, with some success. In 2009, our calculations suggest that the consolidated ROE for PacifiCorp was 8.5%. Regulatory lag remains an issue for the company, although the company is permitted under state regulation to use forward test years for rate cases in Utah, Oregon, Wyoming, and California. (Idaho and Washington require historical test years.)

In 2009, several parties, interveners, and the company reached a settlement to implement fuel and purchased power adjustments, which the IPUC approved. The Utah Public Service Commission (UPSC) is considering the design of a new fuel adjuster, and the company in February 2010 filed to seek approval to defer the difference between the net power costs allowed in the company's 2009 rate case and actual costs incurred. That request is pending before the commission.

Recent general rate case activity includes the company's settlement agreement with the UPSC on Feb. 18, 2010, for a retail rate increase of $32 million, an average price increase of 2%, as compared with the original $67 million sought. In Wyoming, the company has filed a general rate case with the Wyoming Public Service Commission for an increase of as much as $71 million. Early this year, the commission in Oregon approved a stipulation agreement that includes an annual increase to $42 million, as well as three tariff riders for the collection of an additional $8 million that is associated with various cost initiatives over the course of the next three years. In Washington, the commission and PacifiCorp reached a settlement agreement for an annual increase of $14 million, or an average price increase of

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5%. Pro forma rate adjustments in California were made in January 2009 to address energy cost adjustments and attrition adjustments. The company has filed a general rate case with the California Public Utilities Commission for an annual increase of $8 million that remains pending.

PacifiCorp completed $2.3 billion in capital expenditures in 2009, up from $1.8 billion in 2008. The company is projected to spend $4.6 billion in 2010-2012, excluding non-cash allowance for funds used during construction. The largest component of PacifiCorp's capital program is the construction of the Gateway transmission project, an estimated $4.6 billion, 2,000-mile transmission line connecting portions of Wyoming, Utah, Idaho, Oregon, and the southwestern U.S. The project is being completed in phases, with initial portions of new lines being placed in service as early as 2010 and a completion date scheduled for 2018. About 34% of the company's total capital budget over the next three years (2010-2012) is devoted to transmission investment, of which Gateway is a component. In 2008, the Federal Energy Regulatory Commission awarded the company incentive rate treatment of 200 basis points for seven of the eight project segments.

Lower fuel prices, decreased volume of wholesale electricity purchases, and favorable rate approvals on retail electricity sales and sales of renewable energy credits affected PacifiCorp's 2009 results. Although revenues declined slightly, by almost 1%, gross margins per megawatt-hour sold increased by almost 6%, as did the company's earnings before interest and taxes. Operating income increased about 11% due in large part to retail revenues increases provided by regulatory rate relief. For 2009, cash flows from operations rose by $508 million to $1.5 billion, but the majority of this was attributable to the deferred income taxes. In 2009, retail sales declined by 3%, while wholesale sales were approximately flat. About 30%-32% of PacifiCorp's total electric sales are to industrial customers. As a result, we had expected sales contraction to be a drag on 2009 performance, as industrial sales are more sensitive to the business cycle than is residential electric consumption. Industrial sales declined 7% in 2009.

Year-end leverage for the company was 53%, virtually unchanged year over year. Borrowing in 2009 was partially offset by $125 million of equity contribution from MEHC. These equity investments will be key to maintaining a balanced capital structure throughout the company's capital program. Debt to total capitalization reflects several adjustments we make, the largest of which include adding $395 million for power purchase obligations and $370 million for post-retirement obligations. We expect that PacifiCorp will not be in a position to make distributions to its parent while it is executing its capital program and that MEHC will manage PacifiCorp's debt leverage downward to the 50% area in the next several years.

Short-term credit factors

The company's liquidity position is strong. The PacifiCorp 'A-2' short-term rating reflects that although the contingent equity agreement between MEHC and Berkshire supports MEHC and its subsidiaries, the agreement is not a source of instantaneous liquidity. The agreement allows Berkshire up to 180 days to fund a request by MEHC. Given the recent turmoil in both the liquidity and capital markets, we have taken a firmer view on the need to link the PacifiCorp short-term ratings to its stand-alone credit quality, which supports an 'A-2' short-term rating. However, we note that although Berkshire contractually has up to six months to respond to an MEHC call for liquidity, it has strong economic incentives to do so.

PacifiCorp's cash and cash equivalents totaled $117 million as of Dec. 31, 2009. In addition, the company has $1.395 billion in unsecured revolving credit structured in two separate agreements: an $800 million line expiring July 2013 and a $700 million line extending through October 2012. The company had letters of credit in place for $258 million, leaving $1.137 billion available under its revolving facilities.

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PacifiCorp

Outlook

The stable outlook on the PacifiCorp ratings incorporates our expectation that MEHC will continue to support the utility by contributing equity sufficient to ensure that our fully adjusted debt to total capitalization is managed over the next few years to an adjusted level of closer to 50% and that FFO to total debt and FFO interest coverage will be 20% or better and in the range of 4.0x-4.5x, respectively. Given that PacifiCorp's financial risk profile is weak for the current ratings, we do not expect near-term upward ratings momentum for the utility. PacifiCorp's regulatory and structural insulation shields the utility from some MEHC credit deterioration, to an extent. Specifically, our criteria provide that the PacifiCorp CCR can be no more than three notches above the MEHC consolidated credit rating. The company is comfortably within this range, so we do not see significant prospects for the utility rating to fall as a result of adverse rating changes on MEHC, which also enjoys a stable outlook.

Table 1.

PacifiCorp -- Peer Comparison*

	PacifiCorp	Portland General Electric Co.	Pacific Gas & Electric Co.
Rating as of April 28, 2010	A-/Stable/A-2	BBB/Stable/A-2	BBB+/Stable/A-2
	--Average of past three fiscal years--		
(Mil. $)			
Revenues	4,494.3	1,764.0	13,218.9
Net income from cont. oper.	479.7	109.0	1,157.7
Funds from operations (FFO)	1,342.3	326.5	3,039.0
Capital expenditures	1,850.2	511.4	3,437.7
Debt	6,641.7	1,875.2	12,662.8
Equity	5,926.2	1,404.3	10,032.3
Adjusted ratios			
Oper. income (bef. D&A)/revenues (%)	35.8	25.9	29.3
EBIT interest coverage (x)	2.6	2.2	2.9
EBITDA interest coverage (x)	4.0	3.6	4.4
Return on capital (%)	8.0	7.6	10.2
FFO/debt (%)	20.2	17.4	23.9
Debt/EBITDA (x)	4.2	4.1	3.3

*Fully adjusted (including postretirement obligations).

Table 2.

PacifiCorp -- Financial Summary*

	--Fiscal year ended Mar. 31--				
	2009	2008	2007	2006	2005
Rating history	A-/Stable/A-2	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1	A-/Stable/A-1
(Mil. $)					
Revenues	4,457.0	4,498.0	4,258.0	4,154.1	3,998.7
Net income from continuing operations	542.0	458.0	439.0	307.9	360.7
Funds from operations (FFO)	1,760.1	1,272.1	994.8	927.6	864.5
Capital expenditures	2,297.1	1,757.0	1,496.4	1,375.0	1,030.5
Cash and short-term investments	117.0	59.0	228.0	59.0	119.6

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Table 2.

PacifiCorp -- Financial Summary* (cont.)					
Debt	7,415.8	6,635.9	5,873.5	5,473.6	5,185.3
Preferred stock	20.5	41.0	41.0	41.3	41.3
Equity	6,711.5	5,987.0	5,080.0	4,426.8	3,750.7
Debt and equity	14,127.3	12,622.9	10,953.5	9,900.4	8,936.0
Adjusted ratios					
EBIT interest coverage (x)	2.7	2.8	2.8	2.5	3.0
FFO int. cov. (x)	4.9	4.2	3.5	3.8	3.8
FFO/debt (%)	23.7	19.2	16.9	16.9	16.7
Discretionary cash flow/debt (%)	(10.2)	(10.7)	(10.5)	(10.7)	(5.6)
Net cash flow/capex (%)	76.6	72.3	66.3	86.1	86.7
Debt/debt and equity (%)	52.5	52.6	53.6	55.3	58.0
Return on common equity (%)	7.0	6.8	7.8	6.2	8.9
Common dividend payout ratio (unadj.) (%)	7.0	0.0	0.0	5.2	49.1

*Fully adjusted (including postretirement obligations).

Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2009--									
PacifiCorp reported amounts										
	Debt	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	6,416.0	6,732.0	1,609.0	1,609.0	1,060.0	359.0	1,500.0	1,500.0	2.0	2,328.0
Standard & Poor's adjustments										
Operating leases	36.5	--	5.0	2.3	2.3	2.3	2.7	2.7	--	4.1
Intermediate hybrids reported as equity	20.5	(20.5)	--	--	--	1.0	(1.0)	(1.0)	(1.0)	--
Postretirement benefit obligations	369.9	--	20.0	20.0	20.0	5.0	33.8	33.8	--	--
Accrued interest not included in reported debt	111.0	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	35.0	(35.0)	(35.0)	--	(35.0)
Power purchase agreements	395.7	--	63.3	63.3	25.8	25.8	37.5	37.5	--	--
Asset retirement obligations	66.3	--	9.0	9.0	9.0	9.0	5.2	5.2	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	83.0	--	--	--	--	--

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Table 3.

Reconciliation Of PacifiCorp Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)* (cont.)

Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	217.0	--	--
Total adjustments	999.8	(20.5)	97.3	94.6	140.2	76.2	43.1	260.1	(1.0)	(30.9)

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	7,415.6	6,711.5	1,706.3	1,703.6	1,200.2	437.2	1,543.1	1,760.1	1.0	2,297.1

*PacifiCorp reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As of April 13, 2009)

PacifiCorp	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 issue)	BBB
Senior Secured (70 issues)	A
Senior Unsecured (1 issue)	A-
Senior Unsecured (3 issues)	A-/A-2
Senior Unsecured (2 issues)	A/Developing
Corporate Credit Ratings History	
27-Mar-2009	A-/Stable/A-2
18-Sep-2008	A-/Watch Neg/A-1
22-Mar-2006	A-/Stable/A-1
06-Mar-2006	A-/Stable/A-2
25-May-2005	A-/Watch Neg/A-2
Business Risk Profile	Excellent
Financial Risk Profile	Aggressive
Related Entities	
CE Casecnan Water and Energy Co. Inc.	
Senior Secured (1 issue)	BB-/Stable
CE Electric U.K. Funding Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 issue)	BBB+/Stable
CE Generation LLC	
Senior Secured (1 issue)	BB+/Stable
Cordova Energy Co. LLC	
Senior Secured (1 issue)	BB/Stable

Ratings Detail (As Of April 30, 2010) (cont.)	
Iowa-Illinois Gas & Electric Co.	
Senior Unsecured (5 Issues)	A-/A-2
Kern River Gas Transmission Co.	
Senior Secured (2 Issues)	A-/Stable
MidAmerican Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock (1 Issue)	BBB+
Senior Unsecured (9 Issues)	A-
Senior Unsecured (2 Issues)	A-/A-2
MidAmerican Energy Holdings Co.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock (2 Issues)	BBB-
Senior Unsecured (8 Issues)	BBB+
MidAmerican Funding LLC	
Senior Secured (2 Issues)	BBB+
Midwest Power Systems Inc.	
Senior Unsecured (1 Issue)	A-/A-2
Northern Electric Distribution Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured (1 Issue)	A-
Northern Electric Finance PLC	
Senior Unsecured (1 Issue)	A-/Stable
Northern Electric PLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	A-
Northern Natural Gas Co.	
Issuer Credit Rating	A/Stable/--
Senior Unsecured (5 Issues)	A
Salton Sea Funding Corp.	
Senior Secured (3 Issues)	BBB-/Stable
Utah Power & Light Co.	
Senior Secured (1 Issue)	AAA/Negative
Yorkshire Electricity Distribution PLC	
Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured (1 Issue)	A-
Senior Unsecured (1 Issue)	A-/Stable
Yorkshire Electricity Group PLC	
Issuer Credit Rating	BBB+/Stable/--
Yorkshire Power Group Ltd.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (1 Issue)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard

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Ratings Detail (As Of April 12, 2010) (cont.)

& Pmd's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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Exhibit No. 7
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Ratings Direct PPA Debt Imputation

May 2010

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May 7, 2007

Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

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Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms

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are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	5,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 9.0% discount rate	5,030,396						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

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Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

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We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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Case No. PAC-E-10-07
Exhibit No. 8
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

PCRB Variable Rates

May 2010

Indicative Forward PCRB Variable Rates
For Quarter End Periods thru December 31, 2010

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Jan-00	5.81%	3.33%	57%
Feb-00	5.89%	3.62%	62%
Mar-00	6.05%	3.68%	61%
Apr-00	6.16%	4.02%	65%
May-00	6.54%	4.89%	75%
Jun-00	6.65%	4.35%	65%
Jul-00	6.63%	3.99%	60%
Aug-00	6.62%	4.09%	62%
Sep-00	6.62%	4.50%	68%
Oct-00	6.62%	4.36%	66%
Nov-00	6.63%	4.33%	65%
Dec-00	6.68%	4.14%	62%
Jan-01	5.88%	3.10%	53%
Feb-01	5.53%	3.59%	65%
Mar-01	5.13%	3.18%	62%
Apr-01	4.82%	3.72%	77%
May-01	4.16%	3.38%	81%
Jun-01	3.92%	3.03%	77%
Jul-01	3.82%	2.65%	69%
Aug-01	3.64%	2.36%	65%
Sep-01	3.17%	2.42%	76%
Oct-01	2.48%	2.18%	88%
Nov-01	2.13%	1.79%	84%
Dec-01	1.96%	1.64%	84%
Jan-02	1.81%	1.49%	82%
Feb-02	1.85%	1.39%	75%
Mar-02	1.89%	1.46%	77%
Apr-02	1.86%	1.58%	85%
May-02	1.84%	1.67%	91%
Jun-02	1.84%	1.58%	86%
Jul-02	1.83%	1.49%	81%
Aug-02	1.80%	1.49%	83%
Sep-02	1.82%	1.69%	93%
Oct-02	1.81%	1.84%	102%
Nov-02	1.44%	1.66%	115%
Dec-02	1.42%	1.57%	110%
Jan-03	1.36%	1.40%	103%
Feb-03	1.34%	1.43%	107%
Mar-03	1.31%	1.45%	111%
Apr-03	1.31%	1.52%	115%
May-03	1.31%	1.56%	119%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	102%
Aug-03	1.11%	1.16%	104%
Sep-03	1.12%	1.24%	111%
Oct-03	1.12%	1.24%	111%
Nov-03	1.13%	1.36%	121%
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.21%	110%

Indicative Forward PCRB Variable Rates
For Quarter End Periods thru December 31, 2010

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Feb-04	1.10%	1.17%	107%
Mar-04	1.09%	1.20%	110%
Apr-04	1.10%	1.27%	115%
May-04	1.10%	1.29%	117%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%
Aug-04	1.60%	1.40%	88%
Sep-04	1.78%	1.49%	83%
Oct-04	1.90%	1.72%	91%
Nov-04	2.19%	1.65%	75%
Dec-04	2.39%	1.67%	70%
Jan-05	2.49%	1.78%	72%
Feb-05	2.61%	1.88%	72%
Mar-05	2.81%	1.95%	69%
Apr-05	2.97%	2.50%	84%
May-05	3.09%	2.93%	95%
Jun-05	3.25%	2.39%	74%
Jul-05	3.43%	2.28%	67%
Aug-05	3.69%	2.44%	66%
Sep-05	3.78%	2.55%	68%
Oct-05	3.99%	2.66%	67%
Nov-05	4.15%	2.93%	71%
Dec-05	4.36%	3.10%	71%
Jan-06	4.48%	3.02%	67%
Feb-06	4.58%	3.13%	68%
Mar-06	4.76%	3.11%	65%
Apr-06	4.92%	3.45%	70%
May-06	5.08%	3.52%	69%
Jun-06	5.24%	3.74%	71%
Jul-06	5.37%	3.60%	67%
Aug-06	5.35%	3.53%	66%
Sep-06	5.33%	3.61%	68%
Oct-06	5.32%	3.57%	67%
Nov-06	5.32%	3.62%	68%
Dec-06	5.35%	3.70%	69%
Jan-07	5.32%	3.64%	68%
Feb-07	5.32%	3.63%	68%
Mar-07	5.32%	3.64%	68%
Apr-07	5.32%	3.79%	71%
May-07	5.32%	3.90%	73%
Jun-07	5.32%	3.76%	71%
Jul-07	5.32%	3.66%	69%
Aug-07	5.52%	3.76%	68%
Sep-07	5.48%	3.84%	70%
Oct-07	4.98%	3.56%	72%
Nov-07	4.75%	3.53%	74%
Dec-07	5.00%	3.25%	65%
Jan-08	3.95%	3.02%	76%
Feb-08	3.14%	2.86%	91%

Indicative Forward PCRB Variable Rates
For Quarter End Periods thru December 31, 2010

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Mar-08	2.80%	3.79%	135%
Apr-08	2.79%	2.23%	80%
May-08	2.63%	1.93%	73%
Jun-08	2.47%	2.77%	112%
Jul-08	2.46%	4.12%	168%
Aug-08	2.47%	3.03%	123%
Sep-08	2.94%	4.57%	155%
Oct-08	3.87%	4.89%	126%
Nov-08	1.68%	2.34%	139%
Dec-08	1.01%	1.02%	101%
Jan-09	0.39%	0.70%	181%
Feb-09	0.46%	0.68%	147%
Mar-09	0.53%	0.66%	124%
Apr-09	0.45%	0.63%	140%
May-09	0.35%	0.53%	153%
Jun-09	0.32%	0.45%	143%
Jul-09	0.29%	0.41%	142%
Aug-09	0.27%	0.43%	158%
Sep-09	0.25%	0.40%	161%
Oct-09	0.24%	0.39%	159%
Nov-09	0.24%	0.37%	157%
Dec-09	0.23%	0.38%	165%
Average			91%

	Forward 30 Day LIBOR*	Historical Floating Rate PCRB / 30 Day LIBOR	Forecast Floating Rate PCRB
	(1)	(2)	(1) * (2)
3/31/2010	0.33%	91%	0.30%
6/30/2010	0.85%	91%	0.77%
9/30/2010	1.36%	91%	1.23%
12/31/2010	1.50%	91%	1.36%

* Source: Bloomberg L.P. (1/13/10)

Case No. PAC-E-10-07
Exhibit No. 9
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Cost of Preferred Stock

May 2010

PACIFICORP
Electric Operations
Cost of Preferred Stock
Fiscal Year Ending December 31, 2010

Line No.	Description of Issue	Issuance Date	Call Price	Annual Dividend Rate	Shares O/S	Total Par or Stated Value O/S	Net Premium & (Expense)	Net Proceeds to Company	% of Gross Proceeds	Cost of Money	Annual Cost	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
1	**5% Preferred Stock, $100 Par Value**	(a)	110.00%	5.000%	126,243	$12,624,300	($98,049)	$12,526,251	99.223%	5.039%	$636,156	1
2												2
3	**Serial Preferred, $100 Par Value**											3
4	4.52% Series	Oct-55	103.50%	4.520%	2,065	$206,500	($9,676)	$196,824	95.314%	4.742%	$9,793	4
5	7.00% Series	(b)	None	7.000%	18,046	$1,804,600	(c)	$1,804,600	100.000%	7.000%	$126,322	5
6	6.00% Series	(b)	None	6.000%	5,930	$593,000	(c)	$593,000	100.000%	6.000%	$35,580	6
7	5.00% Series	(b)	100.00%	5.000%	41,908	$4,190,800	(c)	$4,190,800	100.000%	5.000%	$209,540	7
8	5.40% Series	(b)	101.00%	5.400%	65,959	$6,595,900	(c)	$6,595,900	100.000%	5.400%	$356,179	8
9	4.72% Series	Aug-63	103.50%	4.720%	69,890	$6,989,000	($30,349)	$6,958,651	99.566%	4.741%	$331,320	9
10	4.56% Series	Feb-65	102.34%	4.560%	84,592	$8,459,200	($49,071)	$8,410,129	99.420%	4.587%	$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		5.414%	$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
19 and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's.
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.
21 (c) Original issue expense/premium has been fully amortized or expensed.
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.
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.
24