Case No. PAC-E-05-1
Exhibit No. 5
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Pro Forma Cost of Long-Term Debt

January 2005

Pro Forma Cost of Long-Term Debt (less current maturities)
As of September 30, 2005

DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	SEGMENT	Coupon*	Weighted Average Maturity
Subtotal - First Mortgage Bonds	$2,284,354,000	($27,346,684)	($13,231,634)	$2,243,775,682	$147,123,610	6.440%	6.186%	12.80
Subtotal - Medium-Term Notes	$955,224,000	($10,745,609)	($27,540,256)	$916,938,136	$72,890,330	7.631%	7.208%	9.83
Total First Mortgage Bonds	$3,239,578,000	($38,092,293)	($40,771,890)	$3,160,713,818	$220,013,940	6.791%	6.488%	11.93
Subtotal - Pollution Control Obligations secured by First Mortgage Bonds	$398,391,834	($10,560,810)	($9,550,194)	$378,280,831	$16,913,508	4.245%	3.598%	16.86
Subtotal - Pollution Control Revenue Bonds	$299,775,000	($3,732,636)	($7,086,097)	$288,956,266	$12,835,515	4.282%	2.980%	12.23
Total PCRB	$698,166,834	($14,293,446)	($16,636,291)	$667,237,097	$29,749,023	4.261%	3.333%	14.87
Total Cost of Long Term Debt	$3,937,744,834	($52,385,739)	($57,408,181)	$3,827,950,915	$249,762,963	6.343%	5.928%	12.45

* Average coupon based on amount currently outstanding.

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt (less current maturities)
September 30, 2005

LINE NO.	BOND INTEREST RATE (1)	DESCRIPTION (2)	MATURITY DATE	ORIGINAL LIFE (3)	PRINCIPAL AMOUNT: ORIGINAL ISSUE (4)	PRINCIPAL AMOUNT: CURRENTLY OUTSTANDING (5)	ISSUANCE EXPENSES (6)	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY: TOTAL DOLLAR AMOUNT (7)	NET PROCEEDS TO COMPANY: PER $100 PRINCIPAL AMOUNT (8)	COST OF MONEY TO COMPANY (BOND TABLE BASIS) (9)	ANNUAL DEBT SERVICE COST (10)	LINE NO.
		First Mortgage Bonds											
1	5.650%	Series due Nov 2006	11/01/06	8	$200,000,000	$200,000,000	($6,855,966)	$0	$193,144,034	96.572%	6.200%	$12,400,000	1
2	4.300%	Series due Sep 2008	09/15/08	5	$200,000,000	$200,000,000	($1,610,660)	($5,967,819)	$192,421,521	96.211%	5.170%	$10,340,000	2
3	6.900%	Series due Nov 2011	11/15/11	10	$500,000,000	$500,000,000	($5,338,849)	$0	$494,661,151	98.932%	7.051%	$35,255,000	3
4	5.450%	Series due Sep 2013	09/15/13	10	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	96.189%	5.961%	$11,922,000	4
5	4.950%	Series due Aug 2014	08/15/14	10	$200,000,000	$200,000,000	($2,028,000)	$0	$197,972,000	98.986%	5.081%	$10,162,000	5
6	7.700%	Series due Nov 2031	11/15/31	30	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	98.766%	7.807%	$23,421,000	6
7	5.900%	Series due Aug 2034	08/15/34	30	$200,000,000	$200,000,000	($2,472,000)	$0	$197,528,000	98.764%	5.989%	$11,978,000	7
8	5.810%	Pro Forma Series	09/30/25	20	$368,524,000	$368,524,000	($3,685,240)	($1,295,995)	$363,542,765	98.648%	5.926%	$21,838,732	8
9	8.271%	C-U Series due Oct 2010 (a)	10/01/10	18	$48,972,000	$20,404,000	$0	$0	$20,404,000	100.000%	8.271%	$1,687,615	9
10	7.978%	C-U Series due Oct 2011 (a)	10/01/11	19	$4,422,000	$2,049,000	$0	$0	$2,049,000	100.000%	7.978%	$163,469	10
11	8.493%	C-U Series due Oct 2012 (a)	10/01/12	20	$19,772,000	$10,375,000	$0	$0	$10,375,000	100.000%	8.493%	$881,149	11
12	8.797%	C-U Series due Oct 2013 (a)	10/01/13	21	$16,203,000	$9,317,000	$0	$0	$9,317,000	100.000%	8.797%	$819,616	12
13	8.734%	C-U Series due Oct 2014 (a)	10/01/14	22	$28,218,000	$17,294,000	$0	$0	$17,294,000	100.000%	8.734%	$1,510,458	13
14	8.294%	C-U Series due Oct 2015 (a)	10/01/15	23	$46,946,000	$29,940,000	$0	$0	$29,940,000	100.000%	8.294%	$2,483,224	14
15	8.635%	C-U Series due Oct 2016 (a)	10/01/16	24	$18,750,000	$12,695,000	$0	$0	$12,695,000	100.000%	8.635%	$1,096,213	15
16	8.470%	C-U Series due Oct 2017 (a)	10/01/17	25	$19,609,000	$13,756,000	$0	$0	$13,756,000	100.000%	8.470%	$1,165,133	16
17	6.186%	Subtotal - First Mortgage Bonds				**$2,284,354,000**	**($27,346,684)**	**($13,231,634)**	**$2,243,775,682**			**$147,123,610**	17

(a) Principal amortizes every October.

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt (less current maturities)
September 30, 2005

LINE NO.	BOND INTEREST RATE (1)	DESCRIPTION (2)	MATURITY DATE	ORIGINAL LIFE (3)	PRINCIPAL AMOUNT: ORIGINAL ISSUE (4)	PRINCIPAL AMOUNT: CURRENTLY OUTSTANDING (5)	ISSUANCE EXPENSES (6)	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY: TOTAL DOLLAR AMOUNT (7)	NET PROCEEDS TO COMPANY: PER $100 PRINCIPAL AMOUNT (8)	MONEY TO COMPANY (BOND TABLE BASIS) (9)	ANNUAL DEBT SERVICE COST (10)	LINE NO.
1		**Series C MTNs**											1
2	7.670%	Series C due Jan 2007	01/10/07	15	$5,724,000	$5,724,000	($36,625)	($783,776)	$4,903,598	85.667%	9.480%	$542,635	2
3	9.150%	Series C due Aug 2011	08/09/11	20	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	99.058%	9.254%	$740,320	3
4	8.950%	Series C due Sep 2011	09/01/11	20	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	99.339%	9.022%	$1,804,400	4
5	8.920%	Series C due Sep 2011	09/01/11	20	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	99.058%	9.023%	$1,804,600	5
6	8.950%	Series C due Sep 2011	09/01/11	20	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	99.298%	9.026%	$2,256,500	6
7	8.290%	Series C due Dec 2011	12/30/11	20	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	85.539%	9.972%	$299,160	7
8	8.260%	Series C due Jan 2012	01/10/12	20	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	85.542%	9.938%	$99,380	8
9	8.280%	Series C due Jan 2012	01/10/12	20	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	85.642%	9.947%	$198,940	9
10	8.250%	Series C due Feb 2012	02/01/12	20	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	85.542%	9.927%	$297,810	10
11	8.530%	Series C due Dec 2021	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	11
12	8.375%	Series C due Dec 2021	12/31/21	30	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	85.539%	9.889%	$494,450	12
13	8.260%	Series C due Jan 2022	01/07/22	30	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	85.642%	9.745%	$487,250	13
14	8.270%	Series C due Jan 2022	01/10/22	30	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	85.542%	9.768%	$390,720	14
15		**Sub-Total Series C**				**$116,724,000**	**($892,158)**	**($5,987,044)**	**$109,844,798**			**$10,926,065**	15
16													16
17		**Series E MTNs**											17
18	7.430%	Series E due Sep 2007	09/11/07	15	$2,000,000	$2,000,000	($15,530)	($226,075)	$1,758,395	87.920%	8.905%	$178,100	18
19	7.220%	Series E due Sep 2007	09/18/07	15	$2,500,000	$2,500,000	($19,412)	($282,594)	$2,197,994	87.920%	8.675%	$216,875	19
20	7.270%	Series E due Sep 2007	09/24/07	15	$4,000,000	$4,000,000	($31,059)	($452,151)	$3,516,790	87.920%	8.730%	$349,200	20
21	8.130%	Series E due Jan 2013	01/22/13	20	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	92.525%	8.939%	$893,900	21
22	8.050%	Series E due Sep 2022	09/01/22	30	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	87.820%	9.258%	$1,388,700	22
23	8.070%	Series E due Sep 2022	09/09/22	30	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	87.820%	9.280%	$742,400	23
24	8.110%	Series E due Sep 2022	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	24
25	8.120%	Series E due Sep 2022	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	25
26	8.050%	Series E due Sep 2022	09/14/22	30	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	87.820%	9.258%	$925,800	26
27	8.080%	Series E due Oct 2022	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	27
28	8.080%	Series E due Oct 2022	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	28
29	8.230%	Series E due Jan 2023	01/20/23	30	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	99.056%	8.316%	$332,640	29
30	8.230%	Series E due Jan 2023	01/20/23	30	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	92.525%	8.951%	$447,550	30
31		**Sub-Total Series E**				**$173,500,000**	**($1,369,553)**	**($17,796,533)**	**$154,333,914**			**$15,913,995**	31
32													32
33		**Series F MTNs**											33
34	7.260%	Series F due Jul 2023	07/21/23	30	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	93.730%	7.804%	$858,440	34
35	7.260%	Series F due Jul 2023	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	35
36	7.230%	Series F due Aug 2023	08/16/23	30	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	97.294%	7.457%	$1,118,550	36
37	7.240%	Series F due Aug 2023	08/16/23	30	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	97.294%	7.467%	$2,240,100	37
38	6.750%	Series F due Sep 2023	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	99.235%	6.810%	$136,200	38
39	6.720%	Series F due Sep 2023	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	99.235%	6.780%	$135,600	39
40	6.750%	Series F due Sep 2023	09/14/23	30	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	98.552%	6.865%	$343,250	40
41	6.750%	Series F due Oct 2023	10/26/23	30	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	99.238%	6.810%	$817,200	41
42	6.750%	Series F due Oct 2023	10/26/23	30	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	99.238%	6.810%	$1,089,600	42
43	6.750%	Series F due Oct 2023	10/26/23	30	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	99.238%	6.810%	$1,362,000	43
44		**Sub-Total Series F**				**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**			**$10,208,020**	44
45													45

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September 30, 2005

LINE NO.	BOND INTEREST RATE	DESCRIPTION	MATURITY DATE	ORIGINAL LIFE	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 (BOND TABLE BASIS)	ANNUAL DEBT SERVICE COST	LINE NO.
	(1)	(2)		(3)	(4)	(5)	(6)		(7)	(8)	(9)	(10)	
46		Series G MTNs											46
47	6.625%	Series G due Jun 2007	06/01/07	12	$100,000,000	$100,000,000	($1,897,428)	($881,696)	$97,220,876	97.221%	6.971%	$6,971,000	47
48	6.710%	Series G due Jan 2026	01/15/26	30	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	99.096%	6.781%	$6,781,000	48
49		**Sub-Total Series G**				**$200,000,000**	($2,801,895)	($881,696)	**$196,316,409**			**$13,752,000**	49
50													50
51		Series H MTNs											51
52	6.375%	Series H due May 2008	05/15/08	10	$200,000,000	$200,000,000	($2,060,179)	$0	$197,939,821	98.970%	6.517%	$13,034,000	52
53	7.000%	Series H due Jul 2009	07/15/09	12	$125,000,000	$125,000,000	($2,428,154)	$0	$122,571,846	98.057%	7.245%	$9,056,250	53
54		**Sub-Total Series H**				**$325,000,000**	($4,488,333)	**$0**	**$320,511,667**			**$22,090,250**	54
55													55
56													56

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September 30, 2005

LINE NO.	BOND INTEREST RATE	DESCRIPTION	ISSUE DATE	MATURITY DATE	ORIGINAL LIFE	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	COST OF MONEY TO COMPANY (BOND TABLE BASIS)	ANNUAL DEBT SERVICE COST	LINE NO.
	(1)	(2)			(3)	(4)	(5)	(6)		(7)	(8)	(9)	(10)	
		SECURED POLLUTION CONTROL REVENUE BONDS												
1	5.650%	Emery County due Nov 2023	11/15/93	11/01/23	30	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	90.394%	6.501%	$3,022,965	1
2	5.625%	Emery County due Nov 2023	11/15/93	11/01/23	30	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	88.813%	6.606%	$1,083,384	2
3	5.625%	Lincoln County due Nov 2021	11/15/93	11/01/21	28	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	89.869%	6.538%	$542,654	3
4	3.900%	Converse 88 due Jan 2014	01/01/88	01/01/14	30	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	95.672%	4.246%	$721,820	4
5	3.900%	Sweetwater 84C due Dec 2014	12/12/84	12/01/14	30	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	98.481%	4.378%	$656,700	5
6	3.400%	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%	4.006%	$1,802,700	6
7	4.125%	Forsyth 86A due Dec 2016 (a)	12/29/86	12/01/16	30	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	96.414%	4.407%	$374,595	7
8	4.125%	Converse 95 due Nov 2025 (a)	11/17/95	11/01/25	30	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	97.509%	4.700%	$249,100	8
9	4.125%	Lincoln 95 due Nov 2025 (a) (b)	11/17/95	11/01/25	30	$22,000,000	$19,921,834	($404,262)	$0	$19,517,573	97.971%	4.344%	$865,404	9
10	2.840%	Carbon County 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%	3.391%	$317,567	10
11	2.840%	Converse County 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%	3.434%	$281,245	11
12	2.840%	Emery County 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%	3.576%	$4,360,574	12
13	2.840%	Lincoln County 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%	3.511%	$528,757	13
14	2.840%	Moffat County due May 2013	11/17/94	05/01/13	19	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	97.666%	3.407%	$1,385,116	14
15	2.840%	Sweetwater County 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%	3.391%	$720,927	15
16	3.598%	**Total - Secured Pollution Control Revenue Bonds**				**$400,470,000**	**$398,391,834**	**($10,560,810)**	**($9,550,194)**	**$378,280,831**			**$16,913,508**	16
17														17
18		**UNSECURED POLLUTION CONTROL REVENUE BONDS**												18
19	2.840%	Sweetwater 88B due Jan 2014	01/01/88	01/01/14	30	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	95.852%	4.183%	$481,045	19
20	2.840%	Sweetwater 90A due Jul 2015	07/24/90	07/01/15	25	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	97.920%	4.069%	$2,848,300	20
21	2.840%	Emery 91 due Jan 2015	05/22/91	01/01/16	25	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	92.353%	4.523%	$2,035,350	21
22	2.840%	Sweetwater 88A due Jan 2017	01/01/88	01/01/17	30	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	97.391%	4.166%	$2,083,000	22
23	2.840%	Forsyth 88B due Jan 2018	01/01/88	01/01/18	30	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	96.903%	4.120%	$1,854,000	23
24	2.840%	Gillette 88 due Jan 2018	01/01/88	01/01/18	30	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	96.704%	4.131%	$1,701,972	24
28	2.840%	Sweetwater 95 due Nov 2025 (a)	11/17/95	11/01/25	30	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	97.322%	4.090%	$997,960	28
29	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%	6.579%	$833,888	29
30	2.980%	**Total - Unsecured Pollution Control Revenue Bonds**				**$321,575,000**	**$299,775,000**	**($3,732,636)**	**($7,086,097)**	**$288,956,266**			**$12,835,515**	30
31														31
32		(a) Subject to Alternative Minimum Tax.												32
33		Annual Debt Service (column 10) includes remarketing fees and credit enhancement fees.												33
34		(b) Currently outstanding amounts are shown net of construction fund balances.												34
35														35

Case No. PAC-E-05-1
Exhibit No. 6
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

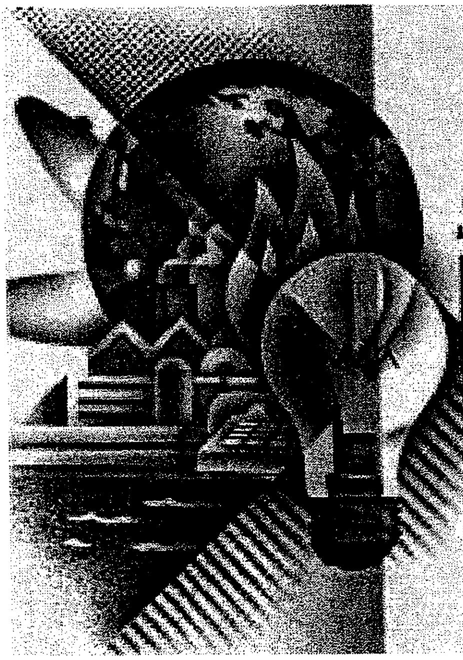
PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Standard & Poor's Utilities & Perspectives - May 12, 2003

January 2005

May 12, 2003
Vol. 12, No. 19



Standard & Poor's

UTILITIES & PERSPECTIVES

GLOBAL UTILITIES RATING SERVICE

STANDARD
&POOR'S

"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery—and thus release from the payment obligation—is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity

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component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as

Table 1

ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	—	—	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2

ABC Utility Co. Adjustment to Pretax Interest Coverage

		Original pretax interest coverage		Adjusted pretax interest coverage	
Net income	120				
Income taxes	65	300		(300+33)	
Interest expense	115	115	= 2.6x	(115+33)	= 2.3x
Pretax available	300				

a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build—i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%—10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (48 plus 11). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means. ■

Jeffrey Wolinsky, CFA
New York (1) 212 438-2117
Dimitri Nikas
New York (1) 212-438-7807
Anthony Flintoff
London (44) 20-7826-3874
Laurence Conheady
Melbourne (61) 3-9631-2036

Case No. PAC-E-05-1
Exhibit No. 7
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Indicative Forward PCRB Variable Rates

January 2005

Idaho Rate Case
Indicative Forward PCRB Variable Rates
For September 30, 2005

	30 Day LIBOR	Floating Rate PCRBs	PCRB / LIBOR
	(a)	(b)	(b)/(a)
Oct-98	5.31%	3.34%	63%
Nov-98	5.24%	3.14%	60%
Dec-98	5.55%	3.26%	59%
Jan-99	4.98%	2.80%	56%
Feb-99	4.94%	2.69%	54%
Mar-99	4.94%	2.93%	59%
Apr-99	4.92%	3.05%	62%
May-99	4.91%	3.24%	66%
Jun-99	5.04%	3.40%	67%
Jul-99	5.18%	2.98%	58%
Aug-99	5.29%	3.11%	59%
Sep-99	5.38%	3.49%	65%
Oct-99	5.41%	3.39%	63%
Nov-99	5.56%	3.38%	61%
Dec-99	6.41%	3.77%	59%
Jan-00	5.81%	3.27%	56%
Feb-00	5.89%	3.64%	62%
Mar-00	6.05%	3.70%	61%
Apr-00	6.16%	3.95%	64%
May-00	6.54%	4.90%	75%
Jun-00	6.65%	4.39%	66%
Jul-00	6.63%	3.77%	57%
Aug-00	6.62%	4.12%	62%
Sep-00	6.62%	4.53%	68%
Oct-00	6.62%	4.23%	64%
Nov-00	6.64%	4.36%	66%
Dec-00	6.69%	4.18%	62%
Jan-01	5.87%	3.03%	52%
Feb-01	5.52%	3.70%	67%
Mar-01	5.13%	3.29%	64%
Apr-01	4.80%	3.85%	80%
May-01	4.16%	3.49%	84%
Jun-01	3.91%	3.13%	80%
Jul-01	3.82%	2.74%	72%
Aug-01	3.64%	2.46%	67%
Sep-01	3.15%	2.50%	79%
Oct-01	2.48%	2.27%	91%
Nov-01	2.13%	1.89%	89%
Dec-01	1.95%	1.79%	92%
Jan-02	1.80%	1.69%	94%
Feb-02	1.85%	1.57%	85%
Mar-02	1.89%	1.69%	90%
Apr-02	1.86%	1.83%	98%

May-02	1.84%	1.86%	101%
Jun-02	1.84%	1.77%	96%
Jul-02	1.83%	1.70%	93%
Aug-02	1.80%	1.70%	95%
Sep-02	1.82%	1.87%	102%
Oct-02	1.80%	2.02%	112%
Nov-02	1.44%	1.86%	129%
Dec-02	1.42%	1.75%	123%
Jan-03	1.36%	1.59%	117%
Feb-03	1.34%	1.61%	120%
Mar-03	1.30%	1.53%	118%
Apr-03	1.31%	1.68%	128%
May-03	1.32%	1.72%	130%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	101%
Aug-03	1.11%	1.16%	105%
Sep-03	1.12%	1.21%	108%
Oct-03	1.12%	1.24%	111%
Nov-03	1.13%	1.28%	114%
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.17%	106%
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%	1.22%	111%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%
Aug-04	1.60%	1.37%	86%
Sep-04	1.78%	1.49%	83%
Average			85%

	Forward 30 Day LIBOR* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
9/30/2005	3.34%	85%	2.84%

* Source: Bloomberg L.P.

Case No. PAC-E-05-1
Exhibit No. 8
Witness: Bruce N. Williams

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams

Pro Forma Cost of Preferred Stock – September 30, 2005

January 2005

PACIFICORP
Electric Operations
Pro Forma Cost of Preferred Stock
September 30, 2005

Line No.	Description of Issue	Issuance Date	Shares Issued and Outstanding	Total Book Value	Net Premium and (Expense)	Net Proceeds to Company	Annual Dividend Requirement	Cost of Money to Company	Annualized Cost	Line No.
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**5% Preferred Stock, $100 Par Value**	(a)	126,243	$12,624,300	($98,049)	$12,526,251	$631,215	5.04%	636,156	1
2										2
3	**Serial Preferred, $100 Par Value**									3
4	4.52% Series	Nov-55	2,065	$206,500	($9,676)	$196,824	$9,334	4.74%	9,793	4
5	7.00% Series	(b)	18,046	$1,804,600	(c)	$1,804,600	$126,322	7.00%	126,322	5
6	6.00% Series	(b)	5,930	$593,000	(c)	$593,000	$35,580	6.00%	35,580	6
7	5.00% Series	(b)	41,908	$4,190,800	(c)	$4,190,800	$209,540	5.00%	209,540	7
8	5.40% Series	(b)	65,959	$6,595,900	(c)	$6,595,900	$356,179	5.40%	356,179	8
9	4.72% Series	Aug-63	69,890	$6,989,000	($30,349)	$6,958,651	$329,881	4.74%	331,320	9
10	4.56% Series	Feb-65	84,592	$8,459,200	($49,071)	$8,410,129	$385,740	4.59%	387,990	10
11										11
12	**No Par Serial Preferred, $25 Stated Value**									12
13	Unamortized expense (e)	May-95							67,955	13
14	Unamortized expense (f)	1995							84,019	14
15										15
16	**No Par Serial Preferred, $100 Stated Value**									16
17	$7.48 Series (d)	Jun-92	487,500	48,750,000	(546,281)	$48,203,719	$3,646,500	7.67%	3,740,666	17
18										18
19	**TOTAL**			$90,213,300	($733,426)	$89,479,874	$5,730,290		5,985,519	19
20										20
21						**Cost of Preferred Stock =**		6.635%		21
22										22
23										23
24										24
25	(a) Issue replaced 6% and 7% preferred stock of Pacific Power & Light Company and Northwestern Electric Company									25
26	and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's.									26
27	(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.									27
28	(c) Original issue expense/premium has been fully amortized or expensed.									28
29	(d) Annual 5% sinking fund begins June 15, 2002.									29
30	(e) Column 10 is the after-tax annual unamortized debt expense related to the 8 3/8% QUIDS redeemed November 2000 assuming a 37% tax rate.									30
31	(f) Column 10 is the after-tax annual unamortized debt expense related to the 8.55% QUIDS redeemed November 2000.									31
32										32