BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1313

In the Matter of IDAHO POWER COMPANY Application for an Accounting Order regarding Certain Excess Net Power Supply Expenses	ORDER

DISPOSITION: STIPULATION ADOPTED

I. BACKGROUND

Idaho Power Company (Idaho Power or the Company) generates more than one-half of its power through hydroelectric generation. When average streamflows are low, the Company must rely on costlier sources of power. For example, when Idaho Power's hydroelectric generation is reduced due to low streamflow conditions, the Company's five thermal generating plants, which produce electricity at higher cost than hydroelectric generation plants, are used more extensively.

Streamflows during the 2007 to 2008 water year were at record lows. Indeed, it has been asserted in this proceeding that "annual inflows into Brownlee during the 2007 water year averaged approximately 13,900 cubic feet per second which is *thirty-two percent lower than normal*."[1](emphasis in original).

On April 30, 2007, Idaho Power made a filing (Application) that requested authorization from the Public Utility Commission of Oregon (Commission) to defer excess net power supply expenses incurred during the extraordinarily low streamflow water year of 2007 to 2008. On May 4, 2007, the Citizens' Utility Board of Oregon (CUB) noticed its intervention in this proceeding. Before a procedural schedule was established, Commission Staff (Staff), Idaho Power and CUB agreed to delay consideration of the Application pending the Commission's decision in docket UE 195, Idaho Power's application for a power cost adjustment mechanism.

On April 28, 2008, the Commission adopted a Power Cost Adjustment Mechanism (PCAM) and an Annual Power Cost Update (APCU) for Idaho Power in

[1] Brief in Support of Stipulation, p. 2.

docket UE 195, Order No. 08-238. The Commission approved the PCAM and the APCU for Idaho Power due to the Company's unique reliance on hydroelectric generation and the associated ratemaking issues.[2] The APCU is comprised of two primary components: an October Power Cost Update (October Update) and a March Power Forecast (March Forecast).

Idaho Power had already filed, on March 24, 2008, a March forecast for 2008 together with tariffs proposing new rates (Schedules 55 and 56). On July 18, 2008, Idaho Power filed a Motion for Clarification of Order No. 08-238. The motion asked the Commission to clarify whether the deferral statute, ORS 757.259, applies to the Company's PCAM. In Order No. 08-491, docket UE 195, the Commission determined that it does apply, and construed the Company's filing of March 24, 2008 to be an application for deferred accounting. Order No. 08-491 grants Idaho Power deferral authority for power supply expense deviations under its PCAM for up to 12 months beginning March 24, 2008.

With the PCAM in place and operating, Staff and the parties agreed to resume consideration of the Application. On January 29, 2009, a prehearing conference was held in this docket. A procedural schedule to address the Company's Application was established on February 2, 2009. Idaho Power, Staff, and CUB (the Stipulating Parties) met for a settlement conference on February 17, 2009. On March 5, 2009, the procedural schedule was suspended to facilitate a stipulation among the Stipulating Parties. On April 8, 2009, the Stipulating Parties filed a Stipulation and a Brief In Support of Stipulation (Stipulating Parties' Brief).

II. THE STIPULATION

The Stipulation, attached to this order as Appendix A, provides that the Stipulating Parties agree that the excess net power supply expense (NPSE) of Idaho Power in its Oregon jurisdiction should be calculated and deferred for the period of May 1, 2007, through March 23, 2008, the beginning date of the deferral authority granted to the Company in Order No. 08-491. The Stipulating Parties determined that the excess NPSE for the deferral period was the result of extraordinarily low streamflow conditions for the 2007 to 2008 water year. As Idaho Power's 2007 Oregon jurisdictional earnings were 3.129 percent, which is well below the Company's authorized return of 7.83 percent, the Stipulating Parties agree that the Company would incur a significant financial impact if the excess NPSE are not deferred.

The Stipulating Parties agree that the total NPSE, and therefore the total amount deferred, should be calculated by dividing the deferral period into two time periods. The Stipulating Parties agree that a different methodology should be used to calculate the NPSE for each period.

Period One of the total deferral period extends for the 8 months from May 1, 2007 through December 31, 2007. Idaho Power's actual NPSE during this period was $232,332,940, on a system-wide basis. This sum exceeded the amount authorized for

[2] Order No. 08-238, p. 1.

recovery in rates for the same period by $196,708,813 on a system-wide basis, and by $9,383,010 on an Oregon jurisdictional basis. The Stipulating Parties use the methodology set forth in section B of the Stipulation to calculate the excess NPSE for Period One. Exhibit A to Appendix A sets forth the actual calculation of the NPSE for Period One. This methodology yields a net deferral amount for Period One of $5,500,307, which the Stipulating Parties agree represents a fair and reasonable amount.

Period Two of the total deferral period extends from January 1, 2008 through March 23, 2008. The Stipulating Parties request that Idaho Power's Period Two NPSE be deferred pursuant to the PCAM agreement established in Order No. 08-238.

The Stipulating Parties agree that the costs serving as the basis for the deferral amounts appear to be prudently incurred, but indicate that the amounts are subject to a prudence review and earnings test at the time amortization is requested. The Stipulating Parties further agree that the total deferral amount authorized in this proceeding will not be amortized until after the deferrals authorized in Order No. 01-307 (docket UM 1007) and Order 07-555 (docket UM 1261)—and any other amounts approved for amortization prior to the Commission's approval in this docket—have been fully amortized. Idaho Power will request amortization of this deferral amount before all previously amortized deferrals are fully amortized.

The Stipulating Parties agree that interest should accrue monthly on the unamortized portion of the deferred amount at the Company's authorized rate of return beginning at the end of the total deferral period (December 31, 2007) until the effective date of an alternative interest rate for Idaho Power's deferred accounts in amortization to be determined in docket UM 1147.[3]

III. DISCUSSION

In Order No. 05-871, entered on July 28, 2005, docket UE 167, the Commission recognized that Idaho Power's system is uniquely reliant on hydroelectric generation. We also acknowledged that this reliance may result in regular excess power supply expenses outside normalized costs predicted in rate case proceedings. We directed Idaho Power to work with Staff and other parties to develop an alternative regulatory mechanism to address the Company's irregular power costs. In Order No. 08-238, we approved a PCAM for Idaho Power, and in Order No. 08-491 we approved the Company's application to defer excess power costs under the terms of the PCAM.

In the interim, between Order No. 05-871 and March 23, 2008 (the beginning date of the deferral authority granted to Idaho Power in docket UE 195, Order No. 08-491), stream flows during the 2007 to 2008 water year sunk to record lows, however. As a result, Idaho Power filed this Application to defer excess NPSE for its Oregon jurisdiction for the period of May 1, 2007 through March 23, 2008.

[3] A stipulation establishing an alternative interest rate for deferred accounts in amortization for Idaho Power is currently under consideration by the Commission in docket UM 1147.

We have examined the Stipulation resolving the issues raised by this Application, as well as the Stipulating Parties' Brief, and the record in the case. We agree with the Stipulating Parties' conclusion that Idaho Power's excess NPSE for the deferral period resulted from extraordinarily low streamflow conditions, and that the Company would likely incur a substantial financial impact without a deferral account in place. We also agree that the excess NPSE for the deferral period produced a benefit for Idaho Power's Oregon customers. We find the proposed deferral is necessary to better match the benefits with costs. We also find that the Stipulation's method for calculating the deferral is reasonable, as is the resulting deferral amount of $5,500,307. We adopt the Stipulation in its entirety.

ORDER

IT IS ORDERED that the Stipulation among Idaho Power Company, Commission Staff, and the Citizens' Utility Board of Oregon, attached as Appendix A, is adopted.

Made, entered, and effective MAY 28 2009.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1313

In the Matter of IDAHO POWER COMPANY Application for Authorization to Defer for Future Rate Recovery Certain Excess Net Power Supply Expense.	**STIPULATION**

INTRODUCTION

The parties to this Stipulation are Idaho Power Company ("Idaho Power" or the "Company"), Staff of the Public Utility Commission ("Staff") and the Citizens' Utility Board of Oregon ("CUB"), (collectively, the "Parties"). The Parties are the only parties to the above-captioned docket.

By entering into this Stipulation the Parties intend to resolve all issues arising from and relating to Idaho Power's Application for Authorization for Future Rate Recovery of Certain Excess Net Power Expenses incurred for the twelve month period commencing May 1, 2007 and ending April 30, 2008 (hereinafter the "Application").

BACKGROUND

Idaho Power filed its Application on April 30, 2007, supported by the testimony of witness Michael J. Youngblood.

CUB filed its Notice of Intervention on May 4, 2007.

On January 29, 2009, Administrative Law Judge Traci A.G. Kirkpatrick presided over a prehearing conference at which the Parties agreed to a procedural schedule.

The Parties met for settlement discussions on February 17, 2009. As a result of these settlement negotiations, the Parties enter into this Stipulation.

STIPULATION

A. The Parties agree on the following:

1. Parties agree to support deferred accounting authority for the period from May 1, 2007, through March 23, 2008, the beginning date of deferral authority granted in UE 195 Order No. 08-491 entered October 6, 2008. The deferral period shall be segregated into two time periods and the calculation of the excess net power supply expense ("NPSE") to be deferred shall use two different methods:
   - Period One is from May 1, 2007 through December 31, 2007,
   - Period Two is from January 1, 2008 through March 23, 2008;

2. The deferral calculation in UM 1313 is limited to the 8-month Period One. Excess NPSE from Period Two will be deferred pursuant to the PCAM agreement established in UE 195 Order No. 08-238 entered April 28, 2008 as part of the Power Cost Variance filing for 2008 and calculated according to the terms of Schedule 56, Power Cost Adjustment Mechanism;

3. In UE 167 the Commission set Idaho Power's total annual NPSE included in rates at $44.6 million on a system-wide basis, resulting in a Unit Cost per MWH of $3.47;

4. Idaho Power's actual NPSE incurred during the Period One deferral period significantly exceeded the amount set in UE 167. Specifically, Idaho Power's actual NPSE during the Period One deferral period were $232,332,940 on a system wide basis. This exceeded the amount recovered in rates for that same time period by $196,708,813 on a system-wide basis;

5. The excess net variable power supply expenses were the result of extraordinarily low streamflow conditions. Idaho Power typically generates more than half of its power through hydro generation at seventeen hydroelectric plants in the Snake River Basin. When streamflow conditions are low, the Company must rely on other, higher cost sources of power. In this case, annual inflows into Brownlee during the 2007 water year averaged approximately 13,900 cubic feet per second which is *thirty-two percent lower than normal.* As a result, the Company was forced to generate more power through its five thermal generating plants with resulting higher fuel costs, and forcing the Company to purchase more power on the open market

6. Absent a deferral, these excess power costs would impose a significant financial impact on the Company;

7. Idaho Power's 2007 Oregon jurisdictional earnings were 3.129%, which is well below the Company's authorized return of 7.83%. Thus the Company could not absorb the excess power costs and earn a reasonable return for the deferral period.

8. Any deferral amount authorized by the Commission in this case will not be amortized until after deferrals authorized in Order 01-307 (UM 1007) and Order 07-555 (UM 1261) – and any other amounts approved for amortization prior to Commission approval in this docket-- have been fully amortized. The Company will file a request for an order allowing amortization of any deferral amount authorized by the Commission in this docket prior to the date on which all deferral amounts amortized before approval in this docket have been fully amortized.

B. The Parties agree that Idaho Power should be allowed to defer excess NPSE incurred from May 1, 2007 to December 31, 2007,[1] for the Oregon jurisdiction in an amount that is the result of compromise by all Parties and that was arrived at using the following methodology:

1. Actual NPSE is the actual expenses recorded in FERC Accounts 501, 547, 447, and 555 accumulated by month on a system wide basis beginning May 1, 2007 and ending December 31, 2007;

2. Actual Sales is the amount of energy required to meet customer demand;

3. The Actual Power Cost per Unit is the Actual NPSE divided by the Actual Sales. For the Period One deferral, the Actual Power Cost per Unit was $22.63 per MWh;

4. The Base NPSE collected in rates is $3.47 per MWh, established in the Company's last general rate case, UE 167;

5. The Excess NPSE for Period One is determined by multiplying the Actual Sales by the difference between the Actual Power Cost per Unit and the Base NPSE collected in rates. The Excess NPSE on a system basis is $196,708,813;

6. The Excess NPSE is multiplied by the Oregon Allocation Factor (4.77% from the 2007 RoO) to determine the Oregon allocated excess NPSE for this period. Deadbands and sharing values are hence forth determined on an Oregon allocated basis using the rate base and cap structure from the 2007 RoO;

7. The amount of Oregon Excess NPSE equal to the value of two thirds of 250 Basis Points ("BP") of return on equity ("ROE") will be the zero adjustment

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[1] The Parties have agreed to the May 1, 2007 to December 31, 2007 period because excess power costs incurred after December 31, 2007 will be recovered through the Company's Power Cost Adjustment Mechanism adopted in UE195.

dead band. This amount will not be subject to recovery and may not be deferred;

8. The amount of Oregon Excess NPSE greater than the value of two thirds of 250 BP of ROE but less than or equal to two thirds of 400 BP of ROE is subject to a 50/50 cost sharing, and as such 50% of this amount is subject to deferral; this is the first sharing band.

9. Any Oregon Excess NPSE greater than the value of two thirds of 400 BP of ROE is subject to a 80/20 customer/company cost sharing so 80% of the remaining Oregon Excess NPSE is subject to deferral; this is the second sharing band.

10. The first and second sharing bands are totaled to determine the Oregon Excess NPSE deferral amount of $6,357,821, including interest on the Oregon deferral amount calculated at the Company's authorized rate of return through December 31, 2007;

11. An adjustment of $857,513, including interest calculated at the Company's authorized rate of return through December 31, 2007, to credit customers for 90% of the Oregon allocated after tax benefits of sales of SO2 emission allowances for the period May 1, 2007- December 31, 2007 is made to the Oregon deferral amount.

The calculations performed to arrive at the deferral amount are shown on Exhibit A to this Stipulation.

C. The Parties agree that the net deferral amount calculated as set forth above, of **$5,500,307** represents a fair and reasonable compromise and satisfies the Parties' respective concerns.

D. Beginning from the end of the deferral period (December 31, 2007) interest should accrue monthly on the unamortized portion of the deferred account at the Company's authorized rate of return. Upon issuance of a Commission order authorizing amortization, the interest rate that should be applied is the rate determined by the methodology adopted by the Commission in the third phase of UM 1147[2].

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[2] The Parties are aware that in Order 07-477 issued in UM 1147, the Commission granted Idaho Power an exception from the general interest rate adopted for amortized deferrals in Order 08-263, directed Staff and the Company to negotiate the appropriate rate for the Company's post-amortization deferrals. Staff and the Company have reached a tentative agreement as to that rate, and will be filing a stipulation with the Commission in the near future.

E. The Parties have reviewed the costs serving as the basis for the deferral amounts and agree that based upon the available information these amounts appear to be prudently incurred. The Parties also agree that the deferred amounts are subject to a prudence review and earnings test at the time of application to amortize the deferred account, as required by ORS 757.259, and do not waive any rights to object to such costs should additional information become available that was not available on the date the Stipulation is filed.

F. The Stipulation is offered into the record of this docket pursuant to OAR 860-014-0085. The Parties agree to support the Stipulation throughout this proceeding and any appeal, to provide witnesses to sponsor the Stipulation at any hearing held in this docket, and recommend that the Commission issue an order adopting the settlement contained herein.

G. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects any material portion of the Stipulation, or conditions its approval upon the imposition of additional material conditions, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration of the Commission's order.

H. By entering into this Stipulation, no party shall be deemed to have approved, admitted to, or consented to the facts, principles, methods, or theories employed by any other party in arriving at the terms of the Stipulation. No party shall be deemed to have agreed that any part of the Stipulation is appropriate for resolving issues arising in any other proceeding.

I. The Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

J. Each Party enters into the Stipulation on the date below.

DATED this 8th day of April, 2009.

STAFF

By:________________________

IDAHO POWER COMPANY

By:________________________

CITIZENS' UTILITY BOARD

By:________________________

J. Each Party enters into the Stipulation on the date below.

DATED this 8th day of April, 2009.

STAFF

By:________________________

IDAHO POWER COMPANY

By:________________________

CITIZENS' UTILITY BOARD

By:________________________

J. Each Party enters into the Stipulation on the date below.

DATED this 8th day of April, 2009.

STAFF

By:____________________

IDAHO POWER COMPANY

By:____________________

CITIZENS' UTILITY BOARD

By:____________________

UM 1313

Exhibit A

to the

Stipulation

of Staff, Idaho Power and Citizens' Utility Board of Oregon (originally filed 4/8/09)

UM 1313: 2007 Deferral of Excess Power Costs
May 2007 through December 2007
Balance as of December 31, 2007

Total Excess Power Cost Deferral:	$ 6,357,820.86
Less 2007 SO2 Sales	(857,513.39)
	$ 5,500,307.47

Oregon Emission Sales: Order 05-983
Deferral Period May 2007 thru April 2008

			2007							
		May	June	July	August	September	October	November	December	Totals
Prior Month Sale(s)	$	0.00	2,495,000.00	4,918,500.00	7,414,500.00	4,823,000.00	0.00	0.00	0.00	19,651,000.00
Brokerage Fee's Paid in Prior Month	$	0.00	(1,000.00)	(2,250.00)	(3,375.00)	(2,125.00)	0.00	0.00	0.00	(8,750.00)
Net Proceeds	$	0.00	2,494,000.00	4,916,250.00	7,411,125.00	4,820,875.00	0.00	0.00	0.00	19,642,250.00
Oregon Allocation		4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
Sharing Percentage		90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Total Customer Benefit	$	0.00	107,067.42	211,054.61	318,159.60	206,960.15	0.00	0.00	0.00	843,241.78
Less Taxes @	39.095%	0.00	(41,858.01)	(82,511.80)	(124,384.49)	(80,911.07)	0.00	0.00	0.00	(329,665.37)
Customer Benefit Net of Tax - Oregon	$	0.00	65,209.41	128,542.81	193,775.10	126,049.08	0.00	0.00	0.00	513,576.41
Principle										
Beginning Balance	$	0.00	0.00	65,209.41	193,752.22	387,527.33	513,576.41	513,576.41	513,576.41	0.00
Amount Deferred		0.00	65,209.41	128,542.81	193,775.10	126,049.08	0.00	0.00	0.00	513,576.41
Ending Balance	$	0.00	65,209.41	193,752.22	387,527.33	513,576.41	513,576.41	513,576.41	513,576.41	513,576.41
Interest										
Beginning Balance	$	0.00	0.00	0.00	425.49	1,689.72	4,218.34	7,569.43	10,920.52	$0.00
Monthly Interest Rate		7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%	7.83%
Monthly Interest	$	0.00	0.00	425.49	1,264.23	2,528.62	3,351.09	3,351.09	3,351.09	14,271.61
Interest Accrued to Date	$	0.00	0.00	425.49	1,689.72	4,218.34	7,569.43	10,920.52	14,271.61	$14,271.61
Deferral Balance Including Interest	$	0.00	65,209.41	194,177.71	389,217.05	517,794.75	521,145.84	524,496.93	527,848.02	527,848.02
Tax Benefit from Above										329,665.37
Total Customer Benefit										857,513.39

EXHIBIT A
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2007 Excess Power Costs Period One Deferral: May 2007 through December 2007

UM 1313 (2007 Deferral)		May	June	July	August	September	October	November	December	Period Total	
ACTUAL POWER COSTS											
Actual NPSE Costs											
Actual Sales - Includes Unbilled	MWh	1,263,003	1,401,406	1,671,870	1,466,219	1,150,737	1,012,621	1,059,499	1,240,964	10,266,319	
Fuel	$	7,980,727.08	11,711,946.25	15,525,826.09	16,019,945.52	11,660,217.94	10,994,126.70	10,607,913.43	10,883,111.36	95,383,814.37	
Purchased Power	$	18,771,589.50	30,645,120.05	37,490,578.99	34,713,027.40	19,361,422.77	12,716,799.06	15,623,672.48	11,665,626.86	180,987,837.11	
Surplus Sales	$	(6,491,031.47)	(17,002,829.11)	(8,336,480.43)	(10,788,902.66)	(14,133,136.88)	(13,708,708.69)	(8,439,917.71)	(891,110.53)	(79,792,117.48)	
Net Hedges	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total Non-QF	$	20,261,285.11	25,354,237.19	44,679,924.65	39,944,070.26	16,888,503.83	10,002,217.07	17,791,668.20	21,657,627.69	196,579,534.00	
QF - Includes Net Metering	$	4,334,632.41	6,206,672.89	6,508,806.50	6,037,646.08	4,729,091.53	3,069,893.86	2,263,446.67	2,603,216.24	35,753,406.18	
Total Actual Power Costs Incurred	$	24,595,917.52	31,560,910.08	51,188,731.15	45,981,716.34	21,617,595.36	13,072,110.93	20,055,114.87	24,260,843.93	232,332,940.18	Total Actual NVPC System basis
Actual Power Cost per Unit	**$/MWh**	**$19.47**	**$22.52**	**$30.62**	**$31.36**	**$18.79**	**$12.91**	**$18.93**	**$19.55**	**$22.63**	
POWER COSTS COLLECTED IN RATES											
Actual Sales	MWh	1,263,003	1,401,406	1,671,870	1,466,219	1,150,737	1,012,621	1,059,499	1,240,964	10,266,319	
Rate by month from GRC UE 167 (Includes CSPP)	**$/MWh**	**$3.47**	**$3.47**	**$3.47**	**$3.47**	**$3.47**	**$3.47**	**$3.47**	**$3.47**	**$3.47**	
Total Power Costs Collected in Rates	$	4,382,620.41	4,862,878.82	5,801,388.90	5,087,779.93	3,993,057.39	3,513,794.87	3,676,461.53	4,306,145.08	35,624,126.93	Base NVPC System Basis
CHANGE FROM FORECAST											
Actual Power Cost per Unit	$/MWh	$19.47	$22.52	$30.62	$31.36	$18.79	$12.91	$18.93	$19.55	$22.63	
Rate by Month from GRC	$/MWh	$3.28	$8.88	$12.04	$9.55	$4.00	$5.09	$9.59	$5.68	$3.47	
Actual Increase (Decrease) Over Forecast Rate	**$/MWh**	**$16.19**	**$13.64**	**$18.58**	**$21.81**	**$14.79**	**$7.82**	**$9.34**	**$13.87**	**$19.16**	
Deviation from Forecast	$	20,213,297.11	26,698,031.26	45,387,342.25	40,893,936.41	17,624,537.97	9,558,316.06	16,378,653.34	19,954,698.85	196,708,813.25	Excess NVPC System Basis

Oregon allocation factor*	4.77%
Oregon share of excess NVPC	$9,383,010
Dead band (two thirds of 250 BP ROE*)	$1,337,047
Oregon share of excess NVPC subject to sharing	$8,045,964
First sharing band: two thirds of difference between 250 and 400 BP	$802,228
Customer's share at 50%	$401,114
Oregon share of remaining excess NVPC above two thirds of 400BP	$7,243,736
Sharing percent	80%
Customer's share at 80%	$5,794,989
Oregon excess NVPC	$6,196,103
Rate of Return	7.83%
Interest on Oregon excess NVPC	$161,718
Total Oregon excess power cost deferral amount as of 12/31/07	$6,357,821

*Based on 2007 Oregon Report of Operations

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May 2007 through December 2007

Period One Deferral 2007 excess power costs
Settlement Position.

UM 1313 (2007 Deferral)		May	June	July	August	September	October	November	December	Period Total	
ACTUAL POWER COSTS											
Actual NPSE Costs											
Actual Sales - Includes Unbilled	MWh	1,263,003	1,401,406	1,671,870	1,466,219	1,150,737	1,012,621	1,059,499	1,240,964	10,266,319	
Fuel	$	7,980,727.08	11,711,946.25	15,525,826.09	16,019,945.52	11,660,217.94	10,994,126.70	10,607,913.43	10,883,111.36	95,383,814.37	
Purchased Power	$	18,771,589.50	30,645,120.05	37,490,578.99	34,713,027.40	19,361,422.77	12,716,799.06	15,623,672.48	11,665,626.86	180,987,837.11	
Surplus Sales	$	(6,491,031.47)	(17,002,829.11)	(8,336,480.43)	(10,788,902.66)	(14,133,136.88)	(13,708,708.69)	(8,439,917.71)	(891,110.53)	(79,792,117.49)	
Net Hedges	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total Non-QF	$	20,261,285.11	25,354,237.19	44,679,924.65	39,944,070.26	16,888,503.83	10,002,217.07	17,791,668.20	21,657,627.69	196,579,534.00	
QF - Includes Net Metering	$	4,334,632.41	6,206,672.89	6,508,806.50	6,037,646.08	4,729,091.53	3,069,893.86	2,263,446.67	2,603,216.24	35,753,406.18	
Total Actual Power Costs Incurred	$	24,595,917.52	31,560,910.08	51,188,731.15	45,981,716.34	21,617,595.36	13,072,110.93	20,055,114.87	24,260,843.93	232,332,940.18	Total Actual NVPC System basis
Actual Power Cost per Unit	$/MWh	$19.47	$22.52	$30.62	$31.36	$18.79	$12.91	$18.93	$19.55	$22.63	
POWER COSTS COLLECTED IN RATES											
Actual Sales	MWh	1,263,003	1,401,406	1,671,870	1,466,219	1,150,737	1,012,621	1,059,499	1,240,964	10,266,319	
Rate by month from GRC UE 167 (Includes CSPP)	$/MWh	$3.28	$8.88	$12.04	$9.55	$4.00	$5.09	$9.59	$5.68	$7.57	
Total Power Costs Collected in Rates	$	4,142,649.84	12,444,485.28	20,129,314.80	14,002,391.45	4,602,948.00	5,154,240.89	10,160,595.41	7,048,675.52	77,685,301.19	Base NVPC System Basis
CHANGE FROM FORECAST											
Actual Power Cost per Unit	$/MWh	$19.47	$22.52	$30.62	$31.36	$18.79	$12.91	$18.93	$19.55	$22.63	
Rate by Month from GRC	$/MWh	$3.28	$8.88	$12.04	$9.55	$4.00	$5.09	$9.59	$5.68	$7.57	
Actual Increase (Decrease) Over Forecast Rate	$/MWh	$16.19	$13.64	$18.58	$21.81	$14.79	$7.82	$9.34	$13.87	$15.06	
Deviation from Forecast	$	20,453,267.68	19,116,424.80	31,059,416.35	31,979,324.89	17,014,647.36	7,917,870.04	9,894,519.46	17,212,168.41	154,647,638.99	Excess NVPC System Basis

4.77%	Oregon 2007 allocation factor
$7,376,692	Excess NVPC (Oregon)
$1,337,047	Dead band (two thirds of 250 BP ROE 2007 RoO
$6,039,646	Excess NVPC subject to sharing (Oregon)
$802,228	First sharing band: two thirds of difference between 250 and 400 BP
$401,114	Customer's share at 50%
$5,237,418	Second sharing band remaining excess NVPC above two thirds of 400BP
80%	Sharing percent
$4,189,934	Customer's share at 80%
$4,591,048	Oregon Excess NVPC for deferral before adjustment
-$929,721	SO2 adjustment
$3,661,327	Oregon Deferral amount
7.83%	Interest at RoR
$109,357	Interest Amount
$4,299,291	Total Oregon 2007 excess power cost deferral amount.

UE 167 Commission Decision (Order 05-871)
Staff Alternative Adjustment to Idaho Power Exhibit No. 13
Power Supply Expenses Normalized Using Idaho Power's Forward Price Curves from April 30, 2004 (On-peak Prices for Purchases, Off-peak Prices for Sales)

	April	May	June	July	August	September	October	November	December	January	February	March	Annual
Hydroelectric Generation (MWh)	850,869.7	859,088.5	858,151.1	759,935.6	726,751.7	675,876.1	541,432.4	456,092.1	662,560.9	796,221.1	832,943.3	817,100.1	8,837,022.5
Bridger													
Energy (MWh)	391,177.1	327,570.9	326,888.8	455,772.4	455,868.7	441,499.2	456,599.6	441,577.7	456,158.0	438,772.7	378,579.5	442,661.3	5,013,126.0
Cost ($ x 1000)	$ 4,986.5	$ 4,175.7	$ 4,167.0	$ 5,810.0	$ 5,811.2	$ 5,628.0	$ 5,820.5	$ 5,629.0	$ 5,814.9	$ 5,593.3	$ 4,826.0	$ 5,642.8	$ 63,904.9
Boardman													
Energy (MWh)	32,832.6	29,961.8	-	38,327.3	38,725.3	37,546.0	38,791.7	37,544.3	38,754.2	35,892.5	31,118.0	36,441.9	395,935.6
Cost ($ x 1000)	$ 434.9	$ 396.9	$ -	$ 507.7	$ 513.0	$ 497.4	$ 513.9	$ 497.3	$ 513.4	$ 475.4	$ 412.2	$ 482.7	$ 5,244.7
Valmy													
Energy (MWh)	114,741.2	151,563.5	148,155.1	163,064.5	163,062.4	157,894.3	162,805.5	157,745.1	163,173.8	162,669.0	145,085.8	78,685.9	1,768,646.1
Cost ($ x 1000)	$ 1,686.7	$ 2,228.0	$ 2,177.9	$ 2,397.1	$ 2,397.1	$ 2,321.1	$ 2,393.3	$ 2,318.9	$ 2,398.7	$ 2,391.3	$ 2,132.8	$ 1,156.7	$ 25,999.8
Danskin													
Energy (MWh)	8.5	137.6	238.7	149.3	166.9	11.0	5.7	7.0	20.3	10.1	13.8	35.6	804.6
Cost ($ x 1000)	$ 0.4	$ 6.6	$ 11.3	$ 7.6	$ 8.0	$ 0.4	$ 0.3	$ 0.3	$ 0.8	$ 0.5	$ 0.7	$ 1.4	$ 38.1
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ 264.4	$ 272.0	$ 264.4	$ 272.0	$ 272.0	$ 264.4	$ 272.0	$ 264.4	$ 272.0	$ 272.0	$ 256.8	$ 272.0	$ 3,218.4
Total Cost	$ 264.8	$ 278.6	$ 275.7	$ 279.6	$ 280.0	$ 264.8	$ 272.3	$ 264.7	$ 272.8	$ 272.5	$ 257.5	$ 273.4	$ 3,256.5
Bennett Mountain													
Energy (MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Capacity Charge - Gas Transportation ($ x 1000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Fuel Costs	$ 7,373.0	$ 7,079.2	$ 6,620.7	$ 8,994.4	$ 9,001.2	$ 8,711.2	$ 8,999.9	$ 8,710.0	$ 8,999.7	$ 8,732.5	$ 7,628.4	$ 7,555.7	$ 98,406.0
Purchased Power (Excluding CSPP)													
Market Energy (MWh)	976.7	18,390.4	40,600.1	44,999.7	31,717.5	12,398.6	1,019.0	19,820.4	25,362.5	10,978.3	2,425.5	2,126.6	210,815.2
Contract Energy (MWh)	-	-	32,400.0	33,480.0	33,480.0	-	-	-	-	-	-	-	99,360.0
Total Energy Excl. CSPP (MWh)	976.7	18,390.4	73,000.1	78,479.7	65,197.5	12,398.6	1,019.0	19,820.4	25,362.5	10,978.3	2,425.5	2,126.6	310,175.2
Market Cost ($ x 1000)	$ 34.4	$ 621.8	$ 1,400.7	$ 2,344.9	$ 1,731.5	$ 627.6	$ 45.5	$ 934.3	$ 1,258.7	$ 612.6	$ 134.0	$ 116.3	$ 9,862.4
Contract Cost ($ x 1000)	$ -	$ -	$ 1,400.0	$ 1,500.0	$ 1,500.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,400.0
Total Cost Excl. CSPP ($ x 1000)	$ 34.4	$ 621.8	$ 2,800.7	$ 3,844.9	$ 3,231.5	$ 627.6	$ 45.5	$ 934.3	$ 1,258.7	$ 612.6	$ 134.0	$ 116.3	$ 14,262.4
Surplus Sales													
Energy (MWh)	477,141.2	339,313.2	244,417.9	105,904.1	123,223.1	229,492.0	215,052.0	71,826.3	162,439.0	275,833.0	393,058.0	386,996.0	3,024,695.7
Revenue Including Transmission Costs ($ x 1000)	$13,383.8	$ 9,144.5	$ 6,721.5	$ 4,620.6	$ 5,632.5	$ 9,725.9	$ 8,042.9	$ 2,835.0	$ 6,749.3	$13,372.4	$ 18,866.8	$ 18,390.1	$ 117,485.3
Transmission Costs ($ x 1000)	$ 477.1	$ 339.3	$ 244.4	$ 105.9	$ 123.2	$ 229.5	$ 215.1	$ 71.8	$ 162.4	$ 275.8	$ 393.1	$ 387.0	$ 3,024.7
Revenue Excluding Transmission Costs ($ x 1000)	$12,906.7	$ 8,805.2	$ 6,477.1	$ 4,514.7	$ 5,509.3	$ 9,496.4	$ 7,827.9	$ 2,763.2	$ 6,586.9	$13,096.5	$ 18,473.7	$ 18,003.1	$ 114,460.6
Net Power Supply Costs ($ x 1000)	$ (5,499.3)	$ (1,104.2)	$ 2,944.3	$ 8,324.6	$ 6,723.4	$ (157.5)	$ 1,217.6	$ 6,881.2	$ 3,671.6	$ (3,751.5)	$(10,711.3)	$(10,331.1)	$ (1,792.2)
PURPA ($ x 1000)	$ 2,815.8	$ 4,160.4	$ 6,508.8	$ 6,702.9	$ 6,422.3	$ 5,081.4	$ 3,792.8	$ 2,204.7	$ 2,193.5	$ 2,164.0	$ 2,073.6	$ 2,292.8	$ 46,413.1
Total Net Power Supply Expense ($ x 1000)	$ (2,683.6)	$ 3,056.2	$ 9,453.1	$15,027.5	$13,145.7	$ 4,923.9	$ 5,010.4	$ 9,085.9	$ 5,865.1	$ (1,587.5)	$ (8,637.7)	$ (8,038.3)	$ 44,620.8
Sales at Customer Level (In 000s MWH)	919.011	932.752	1,063.996	1,248.478	1,376.999	1,231.722	984.776	947.655	1,032.440	1,114.794	1,036.442	974.421	12,863.486
Hours in Month	720	744	720	744	744	720	744	720	744	744	672	744	8760
Unit Cost / MWH (for PCAM)	($2.92)	$3.28	$8.88	$12.04	$9.55	$4.00	$5.09	$9.59	$5.68	($1.42)	($8.33)	($8.25)	$3.47
(1) Repriced:													
Purchased Power	35.19	33.81	34.50	52.11	54.59	50.62	44.66	47.14	49.63	55.80	55.25	54.70	46.78
Surplus Sales	28.05	26.95	27.50	43.63	45.71	42.38	37.40	39.47	41.55	48.48	48.00	47.52	38.84

Determination of Oregon PCAM Deadbands
Based on Idaho Power Report of Operations (Oregon Rep

	2006	2007
Rate Base	**$1,894,794,742**	$ 1,995,045,428
% Equity in cap structure	**51.753%**	**49.960%**
Equity in rate base	$980,613,123	$996,724,696
100 basis points	1.000%	1.000%
Resulting return (NOI Effect)	$9,806,131	$9,967,247
Net-to Gross Factor	**1.64200**	**1.64200**
Revenue requirement	$16,101,667	$\boxed{\$16,366,220}$

Two-thirds of 250 Basis Points

Two thirds of 250-400 Basis Points