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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM MAY 16, 2004 THROUGH MAY 31, 2005.	**CASE NO. IPC-E-04-9** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Donald L. Howell, II, Deputy Attorney General, and responds to the Notice of Application and Notice of Modified Procedure issued in Order No. 29478 on April 22, 2004.

BACKGROUND

On April 15, 2004, Idaho Power Company filed an Application for authority to implement its annual power cost adjustment (PCA) rates. Since 1993 the PCA mechanism has permitted Idaho Power to adjust its rates upward or downward to reflect the Company's annual "power supply costs." Because of its predominant reliance on hydroelectric generation, Idaho Power's actual cost of providing electricity (its power supply costs) varies from year-to-year depending on changes in stream flow and the market price of power. The PCA is designed to allow the Company to recover (or rebate) 90 percent of the above (or below) normal power supply costs experienced by the

Company for providing service in Idaho. The PCA rate is combined with the Company's "base rates"[1] to produce a customer's overall energy rate.

STAFF ANALYSIS

As filed by the Company, this year's PCA has three components: 1) a projection component; 2) a true-up component that corrects for the previous years projection error; and 3) a true up of the previous year's true up that is a final correction.

The PCA Projection

The National Weather Service Northwest River Forecast Center in Portland, Oregon, forecasts the April through July Brownlee Reservoir inflow this year to be 3.13 million acre-feet (maf). This is fifty percent (50%) of the normal expected inflow. A regression equation developed from the results of the general rate case power supply model is used to project "Net Power Supply Costs." *See* Order No. 24806. Using the forecasted 3.13 maf and the regression equation, Staff calculates Net Power Supply Costs for April 2004 through March 2005, to be $83,410,363. As authorized by Commission Order, Staff increased the calculated Net Power Supply Costs by expected qualifying facility costs of $46,413,057 to generate an expected PCA expense of $129,823,420. *See* Staff Attachment A. This is approximately $35.7 million above normal on a total company basis. Staff found that its calculation agreed with Idaho Power's calculation. The calculation of the projection rate component is shown on lines 1 through 6 of Attachment C, where the projection rate component is calculated to be 0.2499¢/kWh. Staff's calculation of the projection rate component agrees with Idaho Power's calculation.

The PCA True up

Exhibit No. 4 to Idaho Power witness Said's testimony illustrates the calculation of the 2003-2004 True up. Staff reviewed Idaho Power's calculation and agrees with its result; Idaho Power under collected power supply costs by $44,285,289 last year in Idaho and, therefore,

[1] The Commission authorizes base rates in a general rate case. The Commission expects to establish new base rates effective June 1, 2004, as a result of the Company's current general rate case, IPC-E-03-13.

customers owe that amount. Staff Attachment B shows the same calculation. The approximate $44.3 million true up is composed as follows:

Last Year's Projection Revenues	$(28.8 Million)
90 % of Last Year's Above Normal Power Supply Costs	$ 69.9 Million
Above Normal PURPA Facilities Costs	$ 4.7 Million
True up Interest	$ 0.5 million
IDACORP Energy Credit	$ (2.0 Million)

Total True up	$ 44.3 Million

The true-up rate component of 0.3661¢/kWh is calculated on line 8 of Attachment C to these comments.

The PCA True up of the True up

As the result of a settlement stipulation reached among the parties in the Company's last PCA case (Case No. IPC-E-03-5) several changes were made to the PCA mechanism. *See* Order No. 29334. One of these changes is that beginning with this PCA filing, under or over collection of the true-up amount will be tracked and trued up. The true-up amount set for recovery in the last PCA case was $38,658,298 and the established true-up rate was 0.3579¢/kWh. Including interest considerations, the approved rate under recovered the true-up amount by $556,693. As shown on Attachment C, line 9, this becomes the true up of the true up PCA rate component of 0.0046¢/kWh. This is the same rate the Company calculated.

PCA Rates

The calculated PCA rate of 0.6206¢/kWh is the sum of the three components listed above (0.2499 + 0.3661 + 0.0046 = 0.6206). However, for reasons stated in its Application, the Company does not wish to increase PCA rates at this time. Therefore, the Company proposes to continue the existing PCA rate of 0.6039¢/kWh for another year. The continuation of the lower rate is expected to cause the Company to under recover the true up by approximately $2 million, which it proposes to recover next year.

Also as a result of the settlement stipulation previously discussed, three rate classes are scheduled to receive an additional credit. These credits are specified in the stipulation. The credits and Company proposed PCA rates for these three schedules (Schedule 7 (small general), Schedule 19 (large power) and Schedule 24 (irrigation)) are shown on lines 16, 17 and 18 of Attachment C, respectively. Line 19 shows the Company proposed PCA rate for all other schedules.

In addition to the Company proposed PCA rate credits just discussed, the Staff believes that customers taking service on those 3 schedules deserve an additional credit. This additional credit is designed to refund to customers the over-collection that the Company will receive as a result of current PCA rates being extended from May 15, 2004 through May 31, 2004.[2] These amounts are associated with the carry-over portion of the 2002/2003 PCA rate, which is why they apply only to Schedules 7, 19 and 24 and it is also why they will not be captured in the true up of the true up.

The total amount of the over-collection is estimated by Staff to be at $605,689. This estimate is based on one-half of May 2003 actual sales and the carry-over portion of the PCA rate currently in effect. If this adjustment is not made, the over-collection amounts will be a windfall to the Company. Any other over collected amounts associated with the two-week extension of the 2003/2004 PCA rates are captured in the true up of the true up and will be refunded in next years PCA. Attachment C, lines 22 through 24, show Staff's proposed rate calculation. Column (d) shows the estimated amount of the over-collection, Column (e) shows expected sales for each schedule and Column (f) shows the proposed rate credit. Finally, Column (g), lines 22 through 25, shows Staff's proposed PCA rates for the coming year in bold print. These rates are the same as those proposed by the Company except they include the two-week rate extension credit.

Lines 28 through 34 of Attachment C calculate total expected PCA revenue for the coming year of $70,643,094.

Attachment D shows the impact on each customer class of the proposed PCA rate change measured from existing rates that include the current PCA. It shows decreases (i.e., credits) for the Irrigation Service class (-16.25 %), Large Power Service class (-6.90 %) and the Small General Service class (-3.78 %). All other class rates remain unchanged. Attachment E shows the impact on each customer class of the proposed PCA rate change measured from base rates that do not include current PCA rates. Attachment E shows, in Column 5, the above normal power supply cost proposed for recovery through the PCA. Normal water conditions and zero true-up balances could eliminate these above normal costs in a future PCA case. At the conclusion of the current general rate case new base rates will be established. The new base rates may cause the percentages in

[2] The Commission authorized the two-week extension in Order No. 29478 at 4-5.

Column 8 to decrease, but the amounts shown in Column 5 that are based on normal consumption will remain the same.

STAFF AUDIT

During the course of the PCA audit, Staff reviewed Company information including the Company's Risk Management Committee (RMC) activities, the power purchases and sales, Danskin expenses and production, and an outage at the Company's Valmy 2 plant in Nevada. The findings of the Staff audit are listed below.

Risk Management Activities

Staff reviewed the Risk Management operating plans, meeting minutes and related materials. The Risk Management Policy Guidelines in place for the 2003-2004 PCA year include: TIER One System Risk Limit of $100 Million; TIER Two Volumetric Limit of +/- 100 MW; TIER Three Price Floor Limits; and a Transaction Price Notification limit of $60/MWh. It appears that the Risk Management Committee (RMC) decisions have been consistent with the Policy Guidelines for this PCA year and that the Company has been implementing the recommendations of the RMC. During this PCA year the risk management methodology has helped to stabilize rates while reducing the upside risk to customers. During the month of July 2003, the Company made purchases that required Commission notification because they were above the $60/MWh threshold amount. Idaho Power also notified the Commission in a timely fashion.

A TIER One violation was also triggered during this PCA year. Idaho Power notified the Commission and RMC Customer Advisory Group members of the violation and explained the proposed activities to address the breach.

Power Purchases and Sales

Staff has reviewed the power purchases and sales for the PCA period. Staff has also reviewed the written purchase and sale policies and found them to be reasonable and prudent. The purchases and sales were made with a variety of credit worthy partners on a timely basis and there were no transactions with IDACORP Energy or other affiliates during this PCA period.

Danskin and Fuel Expenses

The Danskin peaking facility ran more this PCA year than in the 2002 PCA year.[3] According to the Company, the plant was required to run more last summer because Northwest power was not available or there was a transmission constraint that did not allow the import of power. These constraints may have been exacerbated by the outage at the Valmy 2 plant. Danskin also ran for at least a few hours during most of the shoulder months for testing and other purposes. The total Danskin production during the PCA year was 41,197 MWhs. The cost for natural gas was approximately $65 per MWh over the period.

Valmy 2 Plant Outage

During last summer, Idaho Power experienced an unexpected plant outage at the Valmy 2 plant. The plant is a 522 MW coal-fired power plant and is jointly owned (50% each) with Sierra Pacific. Sierra Pacific operates the plant under a management agreement that allows Idaho Power an equal opportunity and responsibility to review operations and set policies. Idaho Power has a management team that oversees the coal-fired facilities and reviews the actions of the managing partner, plant policies and the costs of all its shared thermal plants through oversight investigations and plant visits.

On June 26, 2003, the generator was accidentally energized and sustained severe damage. Because of the accident, the plant was out of service from June 26 until September 8, 2003. In addition to the damage to the generator, the Company was required to purchase replacement power during the plant outage at rates significantly higher than the usual variable costs for Valmy. Idaho Power has included these additional power purchases and associated carrying costs in this PCA to be passed on to customers.

The sequence of events that led up to the accident is clearly documented by the investigation team formed after the accident. Staff has attached an IDACORP internal audit report titled "Valmy Plant Unit 2 Inadvertent Energization Incident" as Confidential Attachment F.[4] The report also included a letter from E.M. Brinson, PE, an Idaho Power consultant who reviewed the report and conducted his own investigation into the incident. Mr. Brinson concluded that the Company's report into the incident was indeed an accurate representation of the events and the factors that

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[3] During the 2003 PCA year, Danskin produced 34,453 MWh compared to 27,789 MWh during the 2002 PCA year.
[4] The document was provided to Staff in response to an audit request and was marked by Idaho Power as "Confidential."

contributed to the incident. A summary of the important events that led up to the accidental energization is set out below.

On June 16, the Valmy Plant Unit 2 was taken offline to repair an air heater bearing. On the morning of June 17, the Unit 2 disconnect switch was "opened", isolating Unit 2 from the switchyard. Later that day Sierra Pacific Substation Control and Test (SCAT) personnel made several modifications to the generator breaker control wiring, allowing power circuit breakers numbers 3600 and 3601 to be closed. Apparently, modifying the control wiring has been a common practice at Valmy to increase reliability for Sierra Pacific's transmission system when a Valmy generating unit is offline. While these modifications may increase reliability for the transmission system, they also defeat specifically engineered protections that were intended to prevent accidental energization of the generator.

On June 26, 2003, after repairs to the air heater bearing were complete, the Valmy 2 unit was brought on line. However, the safety protections were not returned to the normal operating condition. As a result, the generator was accidentally energized and motored[5] for approximately 13 minutes until the control center personnel realized the problem and stopped the generator.

The motoring damaged both the steam turbine and the generator. Damage also occurred in all six turbine bearings, the generator rotor, the generator retaining rings, stator wedges and the steam turbine blades. The causes of the incident were clearly identified in the report prepared by IDACORP internal auditors, Sierra Pacific personnel and the independent consultant. The causes included an apparent failure to follow established safety procedures, a lack of proper supervision and training, and poor communications between project personnel.

According to Idaho Power, its share of the equipment repairs amounted to approximately $1.3 million.[6] While the equipment damages are serious and expensive, another financial impact was caused by the lack of Valmy Unit 2 generation through the summer months. The outage forced Idaho Power to purchase approximately 133.5 MW every hour, or forgo additional power sales that could have been made with excess generation from June 26 through September 9, 2003. The net

[5] Generator motoring occurs when the generator is excited and using power instead of generating power. It can cause rotation of the generator while under a no-load condition. Often motoring occurs with the loss of the prime mover, in this case steam. The loss of the prime mover and a no-load condition can result in the generator spinning beyond its safe speed. Motoring is a significant safety concern and specific features are generally built in to protect against such an event.

[6] Idaho Power and Sierra Pacific have submitted claims to various insurance carriers to recover costs associated with the incident. While some recovery is expected for the equipment costs, it appears that there is no recovery for replacement power from insurance carriers.

cost of the replacement power and lost sales to Idaho Power was initially estimated by the Company to be approximately $6.9 million. However, the Company arrived at this estimate by simply using the average daily Mid-C index prices during the relevant period. The Company's estimate was not based on the actual prices it paid for term purchases, Danskin costs, and real-time purchases used to replace Valmy power at significantly higher costs.

Idaho Power advised Staff that it has not attempted to calculate the exact amount of additional power supply costs due to the incident and has simply included all costs in the PCA accounts for recovery from customers in its current PCA Application. It is Staff's position that the PCA was established to adjust for changes in water conditions and energy market prices. In other words, weather related conditions and power supply costs beyond the control of the Company. It was not designed to automatically flow through costs associated with this type of event. Absent the PCA, these costs would not even be considered without special application from the Company. Presumably, recovery from customers, if allowed at all, would only occur after thorough review.

After reviewing the Company's report on the Valmy 2 outage, Staff recommends that the Commission open a case to formally review the incident and its financial impacts. The incident could have been avoided at several junctions had personnel followed established procedures. Even though Sierra Pacific personnel operate the plant, Idaho Power is an equal partner in oversight and management of the plant. Idaho Power has the opportunity and obligation to review written operating procedures and make sure they are being followed. Idaho Power has since reviewed its own management policies and determined that more oversight of Valmy is necessary.

Given the uncertainly regarding the magnitude of Valmy power replacement costs, Staff further recommends that the Commission reserve recovery of the replacement power costs due to the incident in the amount of at least $9 million until an investigation is completed. Finally, Staff recommends that current PCA rates (with the 3 class exceptions) be continued, but any adjustments in power cost recovery resulting from the formal investigation be carried over to next year's PCA case. This Staff recommendation should not be construed as a disallowance that would require write-off at this time. The need for further review dictates setting the amount aside and deferring a Commission decision until the investigation is complete.

RECOMMENDATIONS

Based on the information reviewed by Staff and presented in these comments, Staff recommends the following:

1. That Idaho Power be allowed to implement a basic PCA rate of 0.6039¢/kWh for all schedules except Schedules 7, 19 and 24, as the Company proposes in its filing.

2. That PCA rates for the three schedules should be as follows: Schedule 7 - 0.5761¢/kWh; Schedule 19 - 0.5730¢/kWh; and Schedule 24 - 0.4976¢/kWh. These rates are lower than those recommended by the Company due to the two-week rate extension credit discussed in these comments.

3. That these rates become effective June 1, 2004 as proposed by the Company.

4. That the Commission open a case to formally review financial impacts of the Valmy incident. Given the uncertainty regarding the magnitude of Valmy 2 replacement power costs, Staff further recommends that the Commission reserve recovery of the replacement power (at a minimum of $9 million) pending further investigation. Finally, Staff recommends that any adjustments in power cost recovery resulting from the formal investigation be carried over to next years PCA without adjustment for this issue in the Company's current PCA rate proposal.

Respectively submitted this 14th day of May 2004.

Donald L. Howell, II
Deputy Attorney General

Technical Staff: Alden Holm
Keith Hessing

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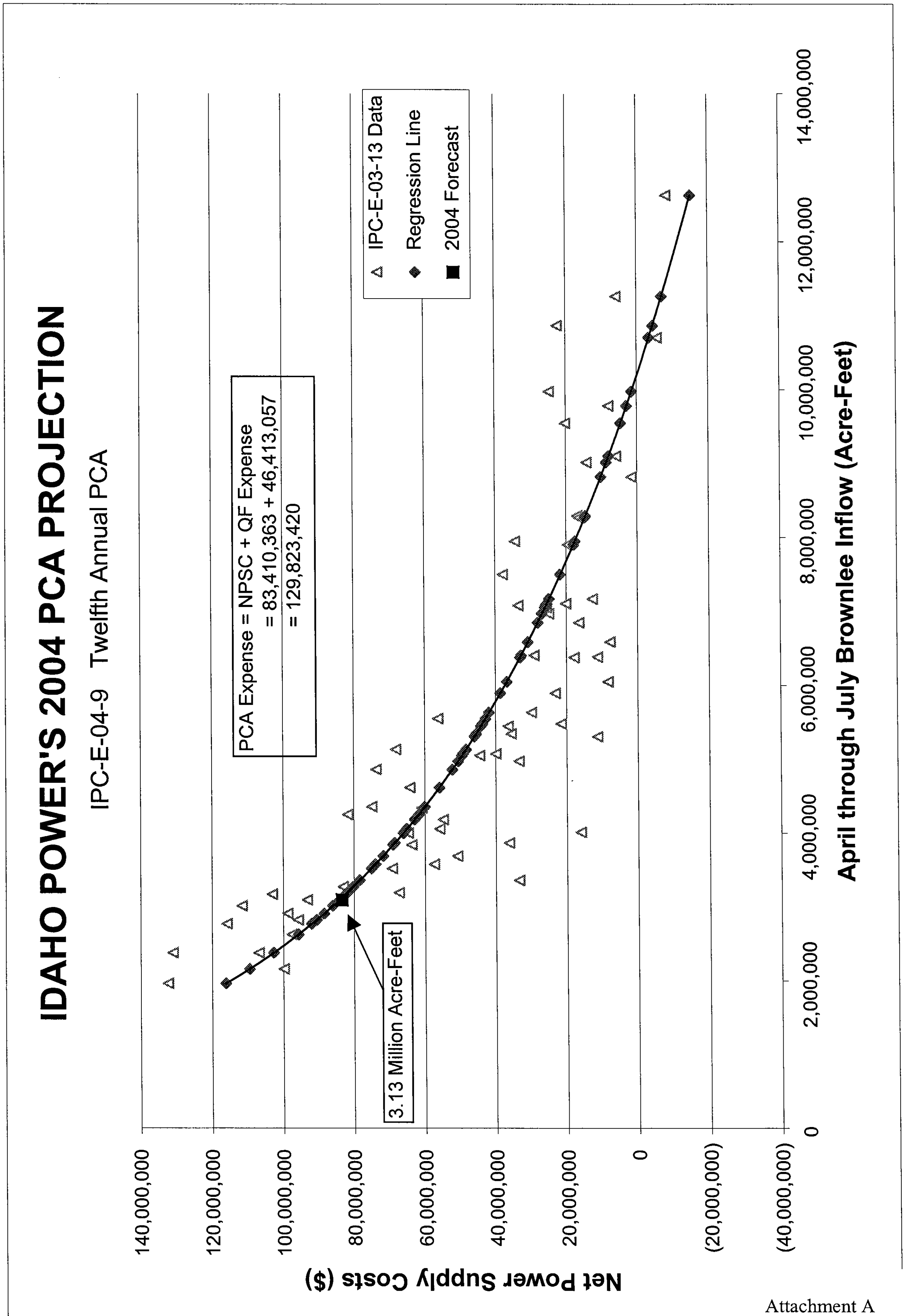

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TRUE-UP CALCULATIONS FOR 2003 - 2004
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-04-9
Staff Case

1	Jurisdictional Allocation Factor	85.0%							
2	Sharing Percentage	90.0%							
3			2003	2003	2003	2003	2003	2003	2003
4	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
5	**PCA Revenue**								
6	Normalized Firm Load	MWh	991,176	1,033,117	1,143,545	1,352,219	1,422,263	1,206,799	1,112,398
7	PCA Component Rate	m/KWh	2.156	2.313	2.460	2.460	2.460	2.460	2.460
8	Revenue Allocated at 85.0%	$	1,816,429	2,031,075	2,391,153	2,827,490	2,973,952	2,523,417	2,326,024
9									
10	**Load Change Adjustment**								
11	Actual Firm Load	MWh	1,005,095	1,206,403	1,513,516	1,725,942	1,511,642	1,220,400	1,085,155
12	Normalized Firm Load	MWh	991,176	1,033,117	1,143,545	1,352,219	1,422,263	1,206,799	1,112,398
13	Load Change	MWh	13,919	173,286	369,971	373,723	89,379	13,601	(27,243)
14	Expense Adjustment (@16.84)	$	(234,396)	(2,918,136)	(6,230,312)	(6,293,495)	(1,505,142)	(229,041)	458,772
15									
16	**Non-QF PCA**								
17	ACTUAL:								
18	Purchased Water	$	0	0	0	0	0	0	0
19	Fuel Expense - Coal	$	7,211,698	8,167,053	7,001,815	7,007,861	6,500,113	9,420,570	7,572,470
20	Fuel Expense - Gas	$	219,529	464,928	396,519	1,500,000	928,967	248,489	213,635
21	Non-Firm Purchases	$	2,957,265	4,189,932	14,091,343	31,072,038	21,970,750	9,132,353	5,184,201
22	Surplus Sales	$	(9,399,118)	(5,354,647)	(2,258,613)	(1,460,784)	(3,880,396)	(7,098,480)	(5,859,374)
23	Expense Adjustment (@16.84)	$	(234,396)	(2,918,136)	(6,230,312)	(6,293,495)	(1,505,142)	(229,041)	458,772
24	Sub-Total	$	754,978	4,549,130	13,000,752	31,825,620	24,014,292	11,473,891	7,569,704
25									
26	BASE:								
27	Fuel Expense	$	3,341,000	2,293,000	2,843,000	5,076,000	6,445,000	5,587,000	6,026,000
28	Non-Firm Purchases	$	339,000	1,356,000	1,872,000	2,473,000	1,252,000	615,000	162,000
29	Surplus Sales	$	(3,195,000)	(597,000)	(208,000)	(142,000)	(595,000)	(1,570,000)	(3,022,000)
30	Surplus Sales Adder	$	(826,063)	(979,683)	(693,151)	(600,808)	(745,141)	(664,245)	(742,240)
31	Sub-Total	$	(341,063)	2,072,317	3,813,849	6,806,192	6,356,859	3,967,755	2,423,760
32									
33	Change From Base	$	1,096,041	2,476,813	9,186,903	25,019,428	17,657,433	7,506,136	5,145,944
34	Deferral (Shared and Allocated)	$	838,471	1,894,762	7,027,981	19,139,862	13,507,936	5,742,194	3,936,647
35									
36	**QF Deferral**								
37	Actual (incl. Meridian Amort.)	$	2,356,255	3,448,832	5,441,988	5,862,008	5,505,591	4,203,308	2,805,035
38	Base	$	2,038,265	3,024,735	5,108,325	5,317,475	5,059,785	3,531,295	2,438,425
39									
40	Change From Base	$	317,990	424,097	333,663	544,533	445,806	672,013	366,610
41	Deferral (Allocated)	$	270,292	360,482	283,614	462,853	378,935	571,211	311,619
42									
43	Credit From IDACORP Energy	$	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)
44	**Total Deferral**	$	(874,333)	57,503	4,753,775	16,608,559	10,746,253	3,623,322	1,755,575
45									
46	**Principal Balances**								
47	Beginning Balance	$	0	(874,333)	(816,830)	3,936,945	20,545,503	31,291,756	34,915,078
48	Amount Deferred	$	(874,333)	57,503	4,753,775	16,608,559	10,746,253	3,623,322	1,755,575
49	Ending Balance	$	(874,333)	(816,830)	3,936,945	20,545,503	31,291,756	34,915,078	36,670,653
50									
51	**Interest Balances**								
52	Accrual thru Prior Month	$	0	0	(1,458)	(2,738)	3,858	38,168	90,385
53	Interest @2% per Year	$	0	(1,457)	(1,361)	6,562	34,243	52,153	58,192
54	Prior Month's Interest Adj.	$	0	(1)	82	34	68	64	3
55	Total Current Month Interest	$	0	(1,458)	(1,279)	6,596	34,311	52,217	58,195
56	Interest Accrued to Date	$	0	(1,458)	(2,738)	3,858	38,168	90,385	148,580
57	**Balance (True-Up & Interest)**	$	(874,333)	(818,288)	3,934,207	20,549,361	31,329,925	35,005,464	36,819,233
58									
59	**True-Up of the True-Up**								
60	True-Up Revenues	$	0	274,737	3,221,294	4,899,594	4,931,935	4,227,044	3,506,083
61									
62	Beginning Balance	$	38,658,298	38,658,298	38,512,422	35,355,315	30,514,647	25,633,570	21,449,248
63	Interest @2% per Year	$	64,430	64,430	64,187	58,926	50,858	42,723	35,749
64	Revenue Applied to Interest	$	0	128,861	64,187	58,926	50,858	42,723	35,749
65	Revenue Applied to Balance	$	0	145,876	3,157,107	4,840,668	4,881,077	4,184,321	3,470,334
66	**True-Up of the True-Up Balance**	$	38,658,298	38,512,422	35,355,315	30,514,647	25,633,570	21,449,248	17,978,914
67									
68	Note: Negative amounts indicate benefit to ratepayers								

Attachment B
Case No. IPC-E-04-9
Staff Comments

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TRUE-UP CALCULATIONS FOR 2003 - 2004
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-04-9
Staff Case

1	Jurisdictional Allocation Factor	85.0%						
2	Sharing Percentage	90.0%						
3			2003	2003	2004	2004	2004	
4	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
5	**PCA Revenue**							
6	Normalized Firm Load	MWh	1,030,835	1,162,545	1,229,083	1,162,223	1,106,080	13,952,283
7	PCA Component Rate	m/KWh	2.460	2.460	2.460	2.460	2.460	
8	Revenue Allocated at 85.0%	$	2,155,476	2,430,882	2,570,013	2,430,208	2,312,813	28,788,931
9								
10	**Load Change Adjustment**							
11	Actual Firm Load	MWh	1,122,562	1,217,213	1,263,507	1,119,830	1,025,276	15,016,541
12	Normalized Firm Load	MWh	1,030,835	1,162,545	1,229,083	1,162,223	1,106,080	13,952,283
13	Load Change	MWh	91,727	54,668	34,424	(42,393)	(80,804)	1,064,258
14	Expense Adjustment (@16.84)	$	(1,544,683)	(920,609)	(579,700)	713,898	1,360,739	(17,922,105)
15								
16	**Non-QF PCA**							
17	ACTUAL:							
18	Purchased Water	$	0	0	0	0	0	0
19	Fuel Expense - Coal	$	8,366,767	8,185,816	9,085,227	8,692,488	8,938,020	96,149,898
20	Fuel Expense - Gas	$	278,959	225,146	213,065	237,681	223,887	5,150,805
21	Non-Firm Purchases	$	3,991,573	12,167,472	4,800,202	3,380,529	4,701,895	117,639,553
22	Surplus Sales	$	(2,150,465)	(6,179,519)	(3,618,339)	(6,381,747)	(17,079,326)	(70,720,808)
23	Expense Adjustment (@16.84)	$	(1,544,683)	(920,609)	(579,700)	713,898	1,360,739	(17,922,105)
24	Sub-Total	$	8,942,151	13,478,306	9,900,455	6,642,849	(1,854,785)	130,297,343
25								
26	BASE:							
27	Fuel Expense	$	6,909,000	7,127,000	6,051,000	5,051,000	4,737,000	61,486,000
28	Non-Firm Purchases	$	345,000	844,000	879,000	642,000	296,000	11,075,000
29	Surplus Sales	$	(3,883,000)	(2,809,000)	(2,978,000)	(2,781,000)	(2,742,000)	(24,522,000)
30	Surplus Sales Adder	$	(625,640)	(739,128)	(799,267)	(769,197)	(889,476)	(9,074,038)
31	Sub-Total	$	2,745,360	4,422,872	3,152,733	2,142,803	1,401,524	38,964,962
32								
33	Change From Base	$	6,196,791	9,055,434	6,747,722	4,500,046	(3,256,309)	91,332,381
34	Deferral (Shared and Allocated)	$	4,740,545	6,927,407	5,162,007	3,442,535	(2,491,076)	69,869,272
35								
36	**QF Deferral**							
37	Actual (incl. Meridian Amort.)	$	2,169,568	2,224,029	1,965,780	1,911,118	1,745,337	39,638,849
38	Base	$	1,539,895	1,713,885	1,567,845	1,459,785	1,314,445	34,114,160
39								
40	Change From Base	$	629,673	510,144	397,935	451,333	430,892	5,524,689
41	Deferral (Allocated)	$	535,222	433,622	338,245	383,633	366,258	4,695,986
42								
43	Credit From IDACORP Energy	$	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(2,000,000)
44	**Total Deferral**	$	2,953,625	4,763,481	2,763,572	1,229,293	(4,604,298)	43,776,326
45								
46	**Principal Balances**							
47	Beginning Balance	$	36,670,653	39,624,277	44,387,758	47,151,331	48,380,624	
48	Amount Deferred	$	2,953,625	4,763,481	2,763,572	1,229,293	(4,604,298)	43,776,326
49	Ending Balance	$	39,624,277	44,387,758	47,151,331	48,380,624	43,776,326	
50								
51	**Interest Balances**							
52	Accrual thru Prior Month	$	148,580	209,697	275,796	349,750	428,329	
53	Interest @2% per Year	$	61,118	66,040	73,980	78,586	80,634	508,688
54	Prior Month's Interest Adj.	$	(1)	59	(26)	(7)	3	278
55	Total Current Month Interest	$	61,117	66,099	73,954	78,579	80,637	508,966
56	Interest Accrued to Date	$	209,697	275,796	349,750	428,329	508,966	
57	**Balance in All Accounts**	$	39,833,974	44,663,555	47,501,081	48,808,953	44,285,292	**44,285,292**
58								
59	**True-Up of the True-Up**							
60	True-Up Revenues	$	3,248,526	3,376,002	3,727,004	3,752,687	3,411,019	38,575,925
61								
62	Beginning Balance	$	17,978,914	14,760,353	11,408,951	7,700,962	3,961,110	
63	Interest @2% per Year	$	29,965	24,601	19,015	12,835	6,602	
64	Revenue Applied to Interest	$	29,965	24,601	19,015	12,835	6,602	474,320
65	Revenue Applied to Balance	$	3,218,561	3,351,401	3,707,989	3,739,852	3,404,417	38,101,605
66	**True-Up of the True-Up Balance**	$	14,760,353	11,408,951	7,700,962	3,961,110	**556,693**	
67								
68	Note: Negative amounts indicate benefit to ratepayers							

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(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Projection 2004-2005:**					
2	PCA Expense	($)	94,101,157	129,823,425	35,722,268	
3	Normalized Energy - Total System	(MWH)	12,863,484	12,863,484		
4	Energy Rate	(¢/kWh)	0.73154	1.00924	0.27770	
5	Sharing Percentage	(%)			90%	
6	Energy Rate Difference	(¢/kWh)			0.249932609	0.2499
7			($)	(MWh)	($/MWh)	(¢/kWh)
8	**True-Up of 2003-2004:**		44,285,289	12,096,838	3.660897914	0.3661
9	**True-Up of the True-Up 2002-2003:**		556,693	12,096,838	0.046019712	0.0046
10	**PCA Rates:**					
11	Calculated PCA Rate Adj. From Base	(¢/kWh)				0.6206
12	Proposed PCA Rate Adj. from Base	(¢/kWh)				0.6039
13	PCA Rate Currently in Effect	(¢/kWh)				0.6039
14	Difference - Last Year to This Year	(¢/kWh)				0.0000
15	O.N. 29334 (IPC-E-03-5) Credits & Rates:				Credit	Rate
16	Schedule 7 - Small General Service	(¢/kWh)			(0.0189)	0.5850
17	Schedule 19 - Large Power Service	(¢/kWh)			(0.0222)	0.5817
18	Schedule 24 - Irrigation & Pump	(¢/kWh)			(0.0811)	0.5228
19	All Other Schedules	(¢/kWh)			0.0000	0.6039
20					Credit	Rate
21	Two Week Rate Extension Credits & Rates:		($)	(MWh)	($/MWh)	(¢/kWh)
22	Schedule 7 - Small General Service		23,572	265,336	(0.0089)	**0.5761**
23	Schedule 19 - Large Power Service		172,939	1,978,824	(0.0087)	**0.5730**
24	Schedule 24 - Irrigation & Pump		409,178	1,620,931	(0.0252)	**0.4976**
25	All Other Schedules				0.0000	**0.6039**
26	**Expected PCA Revenues:**		Rate	Energy	Revenue	
27			($/MWh)	(MWh)	($)	
28	Forecast Revenue		2.499	12,096,838	30,229,998	
29	True Up Revenue		3.494	12,096,838	42,266,352	
30	True Up of True Up Revenue		0.046	12,096,838	556,455	
31	Schedule 7 - Small General Service		(0.278)	265,336	(73,720)	
32	Schedule 19 - Large Power Service		(0.309)	1,978,824	(612,238)	
33	Schedule 24 - Irrigation & Pump		(1.063)	1,620,931	(1,723,753)	
34	Total				70,643,094	
35	Note: Negative rates and amounts indicate benefits to ratepayers.					

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