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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 JUNE 1, 2007 THROUGH MAY 31, 2008.	**CASE NO. IPC-E-07-10** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Donald L. Howell, II, Deputy Attorney General, respectfully submits the following comments in response to Order No. 30302, the Notice of Application and Notice of Modified Procedure issued on April 18, 2007.

BACKGROUND

On April 13, 2007, Idaho Power Company filed its annual Power Cost Adjustment (PCA) Application. 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 cost) varies from year-to-year depending on changes in streamflow and the market price of power. The annual PCA surcharge or credit is combined with the Company's "base rates"[1] to produce a customer's overall energy rate.

In this PCA Application Idaho Power requests recovery of $30.7 million of above normal power supply costs. The Company estimates that this represents a $77.5 million increase in revenues from existing PCA rates (which are below normalized base rates), or an average increase in rates of 14.5%. Attachment A to these comments is a graphic that shows the history of Idaho Power's residential energy rates and identifies the PCA component.

STAFF AUDIT AND ANALYSIS

The 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. Set out below are the Staff's comments on the three PCA components.

A. 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 3.30 million acre-feet (maf). This is only 52% of the average inflow. A regression equation developed from the results of a power supply model run is used to project "Net Power Supply Costs." *See* Order No. 24806 and Staff Attachment B. Using the forecasted 3.30 maf and the regression equation, Staff calculates Net Power Supply Costs for April 2007 through March 2008, to be $75,497,940. As authorized by Commission Order, Staff increased the calculated Net Power Supply Costs by expected PURPA qualifying facility purchases of $54,632,157 and reduced the amount by the expected net benefit of cloud seeding $895,462 ($1,004,538-1,900,000) to generate an expected PCA expense of $129,234,635. This is approximately $28.3 million above normal power supply cost levels 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 0.1888 ¢/kWh. Staff's calculation of the projection rate component agrees with Idaho Power's calculation.

[1] Base rates were established by the Commission in Idaho Power Case No. IPC-E-05-28.

B. The PCA True-up

The PCA True-up captures the difference between the projected power supply costs from the past PCA year and the actual power supply costs that the Company incurred during that same year. Rates were set in the previous PCA period to collect or refund to customers the difference between the projected power supply costs and those costs reflected in rates. The differences between projected power supply costs and actual power supply costs is the PCA deferral balance. This deferral balance, when surcharged or refunded to customers is known as the PCA True-up component.

Exhibit No. 3 to Idaho Power witness Schwendiman's testimony illustrates the calculation of the true-up deferral amount. Attachment D is Staff's calculation of the true-up deferral amount. Staff found no differences in methodology or amounts from those presented by the Company.

As shown on Page 2 of Attachment D, line 64 in the "Totals" column, the true-up amount with interest is $42,115,284. The true up amount used by the Company to calculate the true up rate also included an Emission Allowance tax benefit of $27,025,013, which is not included in Company Exhibit No. 3 or Staff Attachment D. In rounded numbers the true up amount, including the emission allowance tax benefit, is composed as follows:

ITEM	MILLIONS
Last Year's Projection (Rebate)	$ 19.7
90 % of Last Year's Above Normal Power Supply Costs	$ 68.2
Last Year's Above Normal PURPA Facilities Costs	$ (1.6)
Emission Allowance Sales Credit	$(42.1)
Miscellaneous Adjustments (Lines 49, 50)	$ (1.6)
Interest	$ (0.5)
True Up Expense (Deferral)	$ 42.1
Emission Allowance Tax Benefit	$(27.0)
Total True Up Deferral with Emission Tax Benefit	$ 15.1

To verify revenues and costs associated with Idaho Power's true-up deferrals, Staff conducted an audit of all actual revenues and expenses that occurred during the PCA year. These revenues and costs included the cloud seeding program, fuel expenses for coal, fuel expenses for gas, and power purchases and sales. Staff also examined PCA Settlement Agreement Credits from Order No. 29600, Emission Allowance Sales Credit from Order No. 30041, and the Risk

Management operating plans. The following items are included in the PCA true-up:

1. **Water Lease Purchases.** Idaho Power entered into an agreement to purchase 5,000 acre-feet of water (an acre foot of water is enough water to cover an acre, one foot deep) for $14 per acre-foot. The total cost of $70,000 was offset by an agreement with Powerex Corporation. In exchange for the release of the irrigation water, Powerex agreed to pay Idaho Power $7,500. Idaho Power leased the water from Water District 63 in Lucky Peak Reservoir through the Water Supply Bank. Although not a normal, recurring PCA line item, the terms of the agreement for the water lease purchase are reasonable and recovery through the PCA is reasonable because the water is equivalent to fuel for power. The actual water lease purchase expense of $62,500 is a cost to customers and is subject to jurisdictional allocation and 90/10 sharing.

2. **Cloud Seeding Program.** Idaho Power spent approximately $1,108,094 on cloud seeding program costs during the prior PCA year. Beginning in October 2006, upon the completion of the general rate case, IPC-E-05-28 and the issuance of final order, Order No. 30035, monthly cloud seeding expenses and benefits were incorporated into base rates. The net benefit from the cloud seeding program that is included in base rates for this deferral year (October 2006 through March 2007) is $895,462. The actual amount of cloud seeding expense for the PCA period from April 2006 through March 2007 is $804,603. Actual expenses are less than the net benefit included in base rates by $90,559. This represents a benefit to customers and is subject to jurisdictional allocation and 90/10 sharing.

3. **Fuel Expense – Coal.** A large portion of Idaho Powers electricity comes from thermal power produced from coal plants. The three coal plants that Idaho Power owns an interest in are Bridger, Valmy, and Boardman. For the audit period of April 2006 to March 2007 the total coal expense for all plants in operation was $110,532,921. The total coal expense included in base rates is $95,138,364. The increase or decrease in the coal expense from base rates is included in the PCA for recovery from or refund to customers. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $15,394,557. This cost is subject to jurisdictional allocation and 90/10 sharing.

4. **Fuel Expense – Gas.** Idaho Power owns two gas-fired combustion turbine generating plants, Danskin and Bennett Mountain. These plants are both located near Mountain Home and account for 100% of gas usage. For the audit period of April 2006 to March 2007 the total variable gas and gas transportation expense for both plants was $8,181,907. The total gas and gas transportation expense included in base rates is $4,451,500. The increase or decrease in gas

expense from base rates is included in the PCA for recovery from or refund to customers. In this year's PCA deferral balance, the gas expense that is included for future recovery from customers is $3,730,407 and is subject to jurisdictional allocation and 90/10 sharing.

5. Power Purchases and Sales. During the PCA year ending March 31, 2007, the Company sold surplus power totaling $205,529,288, while total power purchases, excluding PURPA contracts, were $224,881,906. The total surplus sales included in base rates is $64,162,300 and the total power purchases included in base rates is $11,842,800. The increase or decrease in the power sales and purchases from base rates is included in the PCA for recovery from or refund to customers and is subject to jurisdictional allocation and 90/10 sharing. Actual surplus sales exceeded base amounts by $141,366,988. This cost difference is a benefit to customers. Actual purchased power amounts exceeded base amounts by $213,039,106. This cost difference becomes a cost to customers. Net surplus sales (surplus power sales greater than power purchases) of $52,319,500 are built into base rates. In this PCA year, actual power purchases exceeded surplus power sales by $19,352,618. The difference between what is built into base rates and the actual expenditures is captured in the PCA deferral. The net of the power purchase difference and the surplus sales difference included in this PCA year for recovery (cost to customers) is $71,672,118. This amount is subject to jurisdictional allocation and 90/10 sharing.

Staff reviewed the power purchases and sales in conjunction with the Company's Risk Management Operating Plans. Our analysis did not find any transaction that was not reasonable or did not follow the Risk Management Committee's recommendations. These transactions were made with an assortment of credit-worthy partners on a timely basis, and there were no transactions conducted with an Idaho Power affiliate.

6. Emission Allowance Sales Credit. In June 2005, Idaho Power Company filed an application requesting blanket authority to sell surplus sulfur dioxide (SO2) allowances; and an accounting order to provide for recording any sale(s) of such allowances. In Order No. 30041, Case No. IPC-E-05-26, the Commission approved and adopted a stipulation providing for the inclusion of the SO2 allowance sales proceeds in the Company's annual PCA, with 90% of the net proceeds to be passed on to customers, and 10% of the net proceeds to be retained as a shareholder benefit. The Commission also ordered that the net of tax, 90% portion of the proceeds allocated to customers in the Stipulation, shall be grossed-up to recognize the tax savings that will accrue when the 90% credit is provided to customers through the PCA.

The Commission found the PCA, which is designed to track and true-up abnormal power supply costs and revenues, to be the logical mechanism to track and distribute proceeds from the sale of excess SO2 allowances. SO2 allowances are allocated to the Company based on the ownership and operation of its thermal/coal powered plants. Excess allowances are a direct result of many factors associated with the operation of the coal plants including installation of environmental equipment, the geographic location of the plant, the total time the plant is operated, the nature of the coal used to fuel the plant, as well as other factors. The allowances accrue as a direct result of plant operation and ownership in much the same way that energy generated from the plant is used to meet ratepayer demand and generate surplus sales revenue to offset plant-operating costs. To the extent that coal costs, environmental costs, and surplus energy sales increase or decrease costs, the cost differences are captured in the PCA and passed through to customers. It is logical that SO2 allowances pass through in a similar manner.

The net proceeds of the emission allowance sales are $81,647,500. The Idaho jurisdictional portion is $76,807,243. The 90% portion to be passed on to customers is $69,126,519, which is the customer benefit after tax amount of $42,101,506 and the tax benefit amount of $27,025,013. The emission allowance sales credit has been properly accounted for in the PCA deferral calculation.

7. Actual Qualifying Facilities Purchases including Net Metering. A Qualifying Facility (QF) is a generating facility which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978 (PURPA) and part 292 of the Federal Energy Regulatory Commission's Regulations (18 C.F.R. Part 292), and which has obtained certification of its QF status.

There are two types of QFs: cogeneration facilities and small power production facilities. Qualifying Facilities are sometimes referred to as cogeneration/small power producers or by the acronym CSPP.

A Cogeneration Facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, residential or institutional purposes, and otherwise meets the requirements of 18 C.F.R. §§ 292.203(b) and 292.205 for operation, efficiency and use of energy output.

A Small Power Production Facility is a generating facility whose primary energy source is renewable (hydro, wind, solar, etc.), biomass, waste, or geothermal resources, and that otherwise meets the requirements of 18 C.F.R. §§ 292.203(a), 292.203(c) and 292.204. Small power production facilities are limited in size to 80 MW, with the exception of certain types of facilities certified prior to 1995 and designated as "eligible" under section 3(17)(E) of the Federal Power Act (FPA) (15 U.S.C. § 796(17)(E), which have no size limitation.

Idaho Power has many contracts with qualifying facilities. For the audit period of April 2006 to March 2007 the actual QF expense is $52,320,145. The QF expense included in base rates is $54,059,005. The increase or decrease in the QF expense from base rates is included in the PCA for recovery from or refund to customers. In this year's PCA deferral balance, the actual QF expense was less than the base QF by $1,738,860. This amount is a benefit to customers and reduces the PCA deferral balance. It is not subject to the 90/10 sharing due to the nature of PURPA contracts in that the Company must purchase the output of the Qualifying Facilities. It is subject to jurisdictional allocation.

8. Settlement Agreement (Order No. 29600). In a Stipulation involving Idaho Power and the Commission Staff, both parties agreed on a single comprehensive settlement amount to resolve several outstanding issues identified in the Stipulation. The parties proposed that the expense adjustment rate for growth (EARG) component in the PCA would continue at the existing value, 16.84 mills per KWH, until the next general revenue requirement case in which the Commission resets the base rates used for PCA computation purposes. Idaho Power also agreed to provide a $19.3 million revenue credit to Idaho Power Customers in the Company's PCA. This revenue credit is a separate $804,166 monthly line item for the months June 2004 through May 2006 in the PCA true-up calculation and includes interest from June 1, 2004 at the PCA carrying charge rate. It was also agreed that the June 2003 Valmy Unit No. 2 incident issues should be resolved in the PCA. The Commission approved the Stipulation in Order No. 29600 issued in September 2004. Staff verified that all settlement components of the Stipulation were incorporated in this PCA Application. The Company has included the proper monthly credit of $804,167 for customers for the months of April and May of 2006, the final two months of the credit resulting from the settlement agreement approved in Order No. 29600.

9. Bennett Mountain Credit. In Order No. 29790, Case No. IPC-E-05-10, the Commission approved recovery of Bennett Mountain power plant costs and required that the related reduction in power supply expense be included in the Company's 2006-2007 PCA. The Company has included the proper monthly amount to reflect the reduction in power supply costs resulting from the Bennett Mountain power plant. The credit began in June 2005 and was to run for 12 months. The current deferral balance includes the final two months of the credit. This credit totals $7,972 and is not subject to the 90/10 sharing.

In final analysis the PCA Forecast and True Up methodology produced an unexpectedly large surcharge deferral balance. The PCA year beginning April 2006 was forecasted to be an above normal water year with below normal power supply costs. A negative forecast rate component was established which credited customers $19.7 million dollars during the true up period. Actual power supply costs captured in the true up calculation were $64.5 million above normal. This amount combined with the forecast credit would have produced a true up amount of $84.2 million. This is a very large amount to accrue in a good or even normal water year. It is only the application of $69.1 million of non-recurring SO2 Emission Allowance Sales benefits that brought the true up amount down to the $15.1 million balance subject to recovery. Without the Emission Allowance Sales benefits the true up amount and rate would have been extremely high in a water year that turned out to be about normal. This result was caused by a number of factors. Base power supply costs are outdated because normalized power supply costs from 2003 are still being used for PCA purposes. These costs were not updated in the IPC-E-05-28 general rate case because of concerns over the AURORA modeled power supply results presented by the Company in that case. The Load Growth Adjustment Factor is also outdated. The factor used during the true up period in this case was $16.84 per MWh. At $16.84 per MWh $10.1 million was adjusted out of the true up amount. The Load Growth Adjustment factor is to be $29.41 per MWh for the next PCA year, which if used last year would have almost doubled the load growth adjustment amount (Case No. IPC-E-06-8, Order No. 30215 dated January 9, 2007). Staff believes that Load Growth Adjustment Factors based on real marginal costs could be much higher. Staff plans to review these and other issues affecting PCA deferral balances as a part of Idaho Power's upcoming general rate case.

C. The PCA True-up of the True-up

The PCA true-up of the true-up amount is the difference between what was anticipated to be collected or refunded when the PCA rate for the true-up was set and what was actually collected or refunded. When special adjustments are not carried into the true up of the true up calculation, the amount represents the under or over recovery of the true up amount from the previous year due to a different amount of kWh being sold than was anticipated in the rate design. The true up of the true up is a benefit to both the Company and customers because any over-collection is returned to customers, and any under-collection is recovered by the Company.

The true-up amount set for recovery in last year's PCA case (IPC-E-06-07) was negative $39,513,704 and the rate calculated to return that amount to customers was -0.3113 ¢/kWh. With other adjustments and interest considerations, the approved rate under refunded the true-up amount by $7,941,094. As shown on Attachment C, line 13, this amount is used to calculate the true-up of the true-up PCA rate component of -0.0589 ¢/kWh. This is the same rate the Company calculated.

PCA RATES

The Staff's calculated PCA rate of 0.2419 ¢/kWh is the sum of the three components listed above (0.1888 + 0.1120 - 0.0589 = 0.2419). This rate is shown on Attachment C, line 16. These are the same rates included in the Company's filing. Staff Attachment E summarizes all PCA rate components and their associated expense amounts. It also shows amounts allocated to other jurisdictions and amounts shared with shareholders.

Attachment F shows the proposed average increase above base rates by class and Attachment G shows the proposed average increase above existing rates by class (last year's PCA rates to this year's PCA rates). In both of these attachments the percentage increase to larger customers is substantially more than the average percentage increase. When power supply costs increase rates, larger customers receive larger than average percentage increases. This results because large customers have lower rates than smaller customers and an equal cents per kWh increase makes a larger percentage difference to them than it does to smaller customers whose base rates are higher.

CONSUMER ISSUES

Idaho Power's PCA Application, filed on April 14, 2007, contained both the customer notice and press release. Staff reviewed them and determined that they complied with the notice requirements of IDAPA 31.21.02.102. The customer notice was mailed with Idaho Power's cyclical billings beginning with the April 26, 2007, statements and ending with the May 24, 2007, statements.

Customers were notified of the Application by bill stuffer and will have until May 14, 2007 to file comments. As of May 8, 2007, the Commission had received six comments. It is apparent from the comments that some customers still do not understand the difference between a PCA filing and a general rate case filing. Two customers who commented did not have an issue with the proposed increase although four customers were very unhappy with the possibility of another rate increase. One customer called the proposal to raise rates a "slap in the face."

Had there not been the decrease in rates during the past twelve months as a result of last year's PCA, the PCA request this year would have been an approximate 4% rate increase for residential customers. Because the roughly 10% rate reduction to residential bills from the 2006 PCA will no longer be in effect after May 31, 2007, residential customers will see a nearly 14% net rate increase when compared with last year's rates should this year's PCA be approved.

PCA RECOMMENDATIONS

Staff's review identified no adjustments to the Company's calculations. Staff recommends that the Commission approve the PCA rates as filed by the Company. Staff recommends that these PCA rates become effective June 1, 2007.

Respectfully submitted this 14th day of May 2007.

Donald L. Howell, II for
Donald L. Howell, II
Deputy Attorney General

Technical Staff: Keith Hessing
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Marilyn Parker

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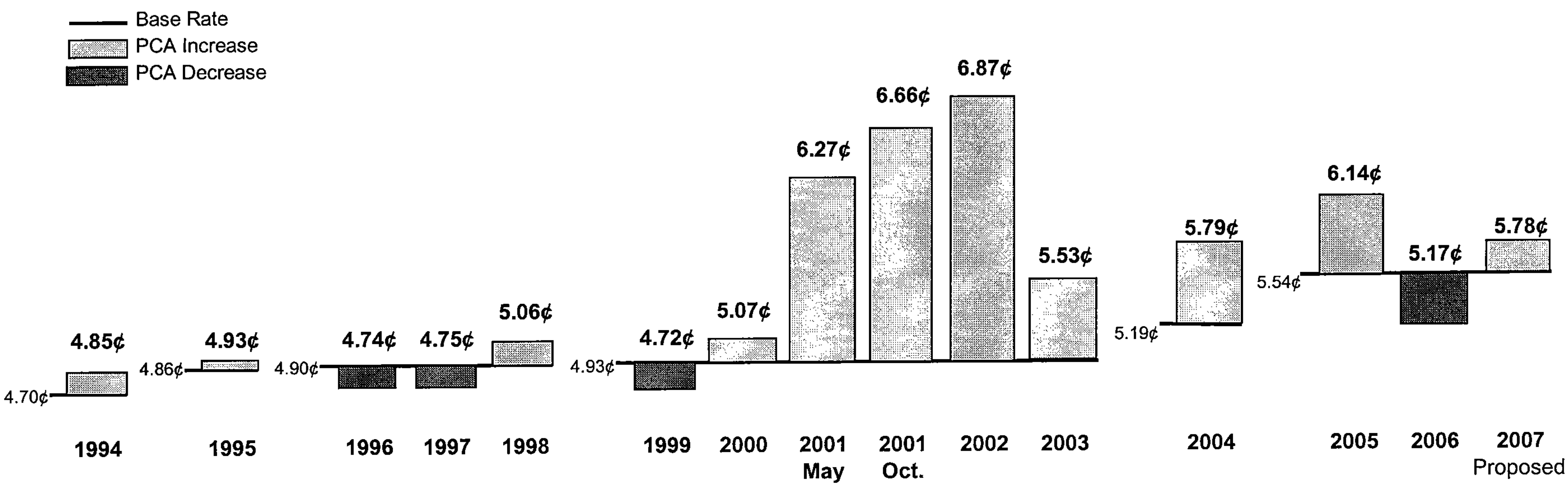
AVERAGE RESIDENTIAL ENERGY RATES FOR IDAHO POWER COMPANY

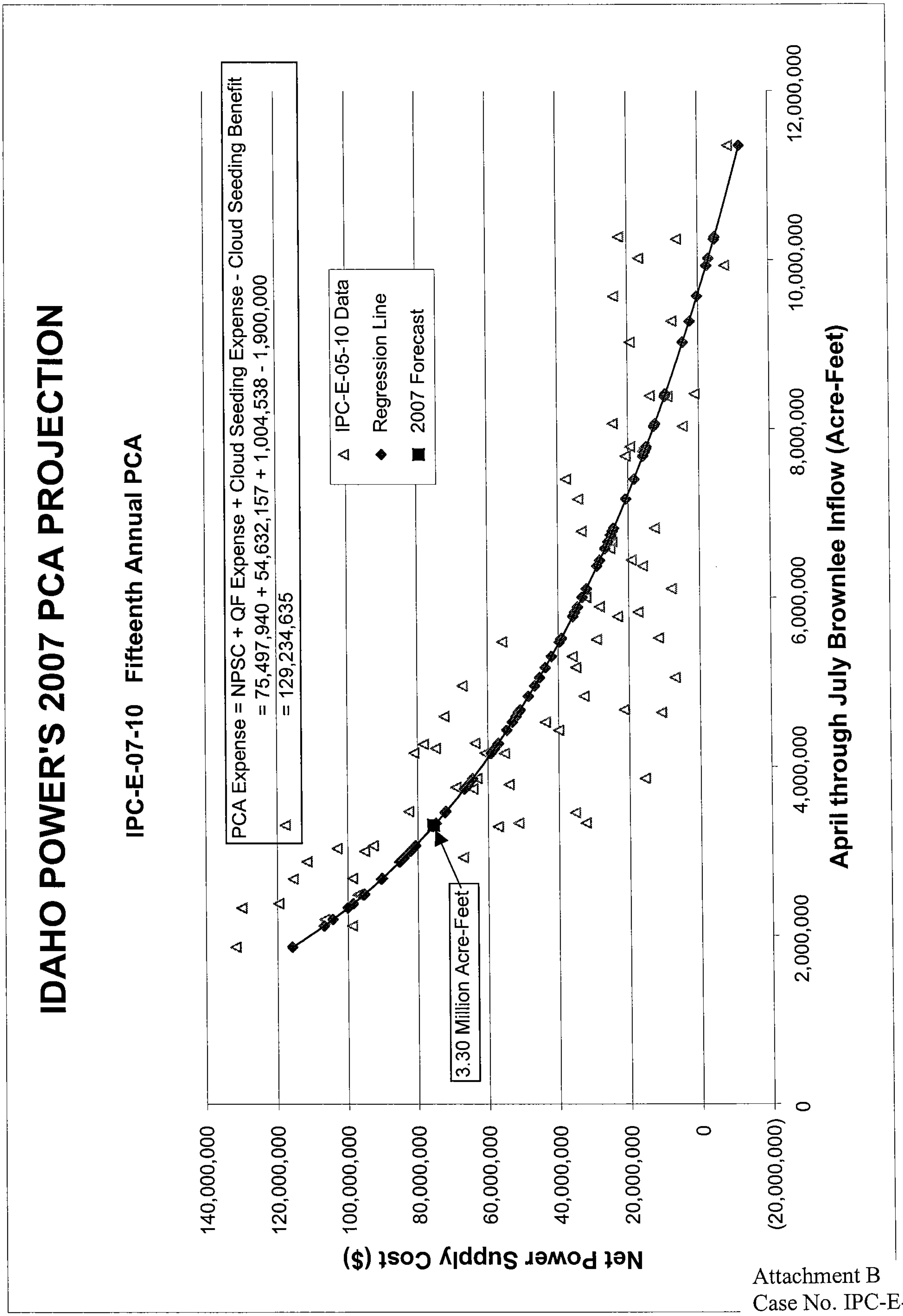
Cents per Kilowatt-hour



These rates do not include the monthly Service Charge, the BPA Credit, the Energy Efficiency Rider or any Local Franchise Fees that may apply.

Attachment A
Case No. IPC-E-07-10
Staff Comments
5/14/07

U:\khessin\IPCE0710\PCA History Chart 5/8/2007 KDH



Attachment B
Case No. IPC-E-07-10
Staff Comments
5/14/07

2007-2008 PCA - Fifteenth Annual
IPC-E-07-10
Staff Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Projection 2007-2008:**					
2	PCA Expense	($)	100,916,459	129,234,635	28,318,176	
3	Normalized System Firm Sales	(MWH)	13,497,550	13,497,550		
4	Energy Rate	(¢/kWh)	0.74767	0.95747	0.20980	
5	Sharing Percentage	(%)			90%	
6	Forecast Rate	(¢/kWh)			0.188822108	0.1888
7						
8						
9			($)	(MWh)	($/MWh)	(¢/kWh)
10						
11	**True-Up of 2006-2007:**		15,090,267	13,475,244	1.119851114	0.1120
12						
13	**True-Up of the True-Up:**		(7,941,094)	13,475,244	-0.589309848	(0.0589)
14						
15	**PCA Rates:**					
16	PCA Rate Adjustment From Base	(¢/kWh)				0.2419
17	PCA Rate Currently in Effect	(¢/kWh)				(0.3689)
18	Difference - Last Year to This Year	(¢/kWh)				0.6108
19						
20	Note: Negative rates and amounts indicate benefits to ratepayers.					

TRUE-UP CALCULATIONS FOR 2006 - 2007
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-07-10
Staff Case

1			2006	2006	2006	2006	2006	2006	2006
2	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
3	**PCA Revenue**								
4	Normalized Idaho Jurisd. Sales	MWh	862,931	881,064	1,074,252	1,273,977	1,295,480	1,168,367	996,812
5	Forecast Rate	m/KWh	4.288	4.288	-2.507	-2.507	-2.507	-2.507	-2.507
6	Revenue	$	3,700,248	3,778,002	(2,693,150)	(3,193,860)	(3,247,768)	(2,929,096)	(2,499,008)
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	987,134	1,252,090	1,455,481	1,751,828	1,546,516	1,213,236	1,098,789
10	Normalized Firm Load	MWh	974,066	1,142,316	1,395,617	1,567,783	1,482,896	1,185,594	1,080,868
11	Load Change	MWh	13,068	109,774	59,864	184,045	63,620	27,642	17,921
12	Expense Adjustment (@16.84)	$	(220,065)	(1,848,594)	(1,008,110)	(3,099,318)	(1,071,361)	(465,491)	(301,790)
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	Water Lease Purchases	$	0	0	0	0	0	0	0
17	Cloud Seeding Program	$	62,223	60,860	25,381	18,559	23,731	42,983	45,175
18	Fuel Expense - Coal	$	5,546,615	6,095,688	7,741,233	10,085,118	10,880,041	10,919,871	9,801,716
19	Fuel Expense - Danskin	$	73,786	221,367	336,649	1,319,234	587,423	125,246	(6,289)
20	Fuel Expense - Bennett Mountain	$	132,815	580,697	1,060,247	592,883	0	478,756	260,328
21	Non-Firm Purchases	$	16,805,367	21,235,507	21,621,438	32,424,611	27,710,694	17,680,017	10,081,382
22	Surplus Sales	$	(33,649,301)	(22,745,928)	(16,169,244)	(7,089,391)	(12,918,832)	(17,442,355)	(13,612,384)
23	Expense Adjustment (@16.84)	$	(220,065)	(1,848,594)	(1,008,110)	(3,099,318)	(1,071,361)	(465,491)	(301,790)
24	Sub-Total	$	(11,248,560)	3,599,597	13,607,594	34,251,696	25,211,696	11,339,027	6,268,138
25									
26	BASE:								
27	Fuel Expense - Coal	$	7,108,200	6,800,600	6,342,000	8,714,200	8,720,308	8,448,908	8,726,408
28	Fuel Expense - Danskin	$	264,800	278,500	275,700	279,600	280,800	264,700	272,300
29	Fuel Expense - Bennett Mountain	$	0	0	406,100	253,200	256,700	20,900	22,400
30	Non-Firm Purchases	$	28,000	664,100	2,715,400	3,166,600	2,765,200	479,300	35,800
31	Surplus Sales	$	(9,187,500)	(6,566,900)	(4,831,500)	(2,542,200)	(3,601,100)	(5,736,200)	(5,012,200)
32	Cloud Seeding Expense	$	0	0	0	0	0	0	167,423
33	Cloud Seeding Benefit	$	0	0	0	0	0	0	(316,667)
34	Sub-Total	$	(1,786,500)	1,176,300	4,907,700	9,871,400	8,421,908	3,477,608	3,895,464
35									
36	Change From Base	$	(9,462,060)	2,423,297	8,699,894	24,380,296	16,789,788	7,861,419	2,372,674
37	Emission Allowance Sales Credit	$	0	0	(49,712,488)	0	0	0	0
38	Sub-Total	$	(9,462,060)	2,423,297	(41,012,594)	24,380,296	16,789,788	7,861,419	2,372,674
39									
40	Deferral (Shared and Allocated)	$	(8,013,419)	2,052,290	(34,733,566)	20,647,673	14,219,272	6,657,836	2,009,418
41									
42	**QF Deferral**								
43	Actual (includes Net Metering)	$	3,294,788	4,457,705	7,097,652	7,782,423	7,165,189	5,608,889	3,919,787
44	Base	$	2,815,766	4,160,399	7,292,829	7,540,664	7,158,661	5,503,768	4,561,853
45									
46	Change From Base	$	479,022	297,306	(195,177)	241,759	6,528	105,121	(642,066)
47	Deferral (Allocated)	$	450,760	279,765	(183,662)	227,495	6,143	98,919	(604,184)
48									
49	Settlement Agreement (ON 29600)	$	(804,167)	(804,167)	0	0	0	0	0
50	Bennett Mtn. Credit (ON 29790)	$	(3,986)	(3,986)	0	0	0	0	0
51	**Total Deferral** (-6+40+47+49+50)	$	(12,071,060)	(2,254,100)	(32,224,077)	24,069,028	17,473,183	9,685,850	3,904,241
52									
53	**Principal Balances**								
54	Beginning Balance	$	0	(12,071,060)	(14,325,160)	(46,549,237)	(22,480,209)	(5,007,026)	4,678,824
55	Amount Deferred	$	(12,071,060)	(2,254,100)	(32,224,077)	24,069,028	17,473,183	9,685,850	3,904,241
56	Ending Balance	$	(12,071,060)	(14,325,160)	(46,549,237)	(22,480,209)	(5,007,026)	4,678,824	8,583,066
57									
58	**Interest Balances**								
59	Accrual thru Prior Month	$	0	0	(30,179)	(515,182)	(737,922)	(792,238)	(807,259)
60	Interest @ 3% per Year	$	0	(30,178)	(35,813)	(116,373)	(56,201)	(12,518)	11,697
61	Prior Month's Interest Adj.	$	0	(1)	(449,190)	(106,367)	1,884	(2,503)	0
62	Total Current Month Interest	$	0	(30,179)	(485,003)	(222,740)	(54,317)	(15,021)	11,697
63	Interest Accrued to Date	$	0	(30,179)	(515,182)	(737,922)	(792,238)	(807,259)	(795,562)
64	**Balance (True-Up & Interest)**	$	(12,071,060)	(14,355,339)	(47,064,419)	(23,218,131)	(5,799,264)	3,871,566	7,787,504
65									
66	**True-Up of the True-Up**								
67	True-Up Revenues (Collections)	$	1,619,149	1,573,833	946,500	(1,966,009)	(1,118,311)	(1,486,632)	(1,169,515)
68									
69	Beginning Balance	$	24,513,298	(16,657,056)	(18,272,532)	(19,264,713)	(17,680,713)	(16,606,604)	(15,161,489)
70	Adjustments:								
71	2005-06 PCA Transfer (ON 30047)	$	(39,513,704)	0	0	0	0	0	0
72	Tax Settlement True-Up (ON 29789)	$	0	0	0	(333,015)	0	0	0
73		$	0	0	0	0	0	0	0
74	Sub-Total	$	(15,000,406)	(16,657,056)	(18,272,532)	(19,597,728)	(17,680,713)	(16,606,604)	(15,161,489)
75	Interest @ 3% per Year	$	(37,501)	(41,643)	(45,681)	(48,994)	(44,202)	(41,517)	(37,904)
76	Revenue Applied to Interest	$	(37,501)	(41,643)	(45,681)	(48,994)	(44,202)	(41,517)	(37,904)
77	Revenue Applied to Balance	$	1,656,650	1,615,476	992,181	(1,917,015)	(1,074,109)	(1,445,115)	(1,131,611)
78	**True-Up of the True-Up Balance**	$	(16,657,056)	(18,272,532)	(19,264,713)	(17,680,713)	(16,606,604)	(15,161,489)	(14,029,877)
79									
80	Note: Negative amounts indicate benefit to ratepayers								

TRUE-UP CALCULATIONS FOR 2006 - 2007
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-07-10
Staff Case

1			2006	2006	2007	2007	2007	
2	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
3	**PCA Revenue**							
4	Normalized Idaho Jurisd. Sales	MWh	912,336	1,021,056	1,096,401	1,032,663	971,533	12,586,872
5	Forecast Rate	m/KWh	-2.507	-2.507	-2.507	-2.507	-2.507	
6	Revenue	$	(2,287,226)	(2,559,787)	(2,748,677)	(2,588,886)	(2,435,633)	(19,704,842)
7								
8	**Load Change Adjustment**							
9	Actual System Firm Load - Adjusted	MWh	1,142,940	1,346,182	1,382,283	1,106,621	1,089,553	15,372,653
10	Normalized Firm Load	MWh	1,122,464	1,274,108	1,265,091	1,092,645	1,078,723	14,662,171
11	Load Change	MWh	20,476	72,074	117,192	13,976	10,830	710,482
12	Expense Adjustment (@16.84)	$	(344,816)	(1,213,726)	(1,973,513)	(235,356)	(182,377)	(11,964,517)
13								
14	**Non-QF PCA**							
15	ACTUAL:							
16	Water Lease Purchases	$	0	0	62,500	0	0	62,500
17	Cloud Seeding Program	$	58,725	120,999	57,852	173,888	114,227	804,603
18	Fuel Expense - Coal	$	10,224,908	9,815,731	10,253,901	9,431,155	9,736,944	110,532,921
19	Fuel Expense - Danskin	$	164,780	49,806	0	151,429	99,939	3,123,370
20	Fuel Expense - Bennett Mountain	$	662,445	139,155	530,042	11,446	609,723	5,058,537
21	Non-Firm Purchases	$	11,368,260	21,860,906	21,841,568	11,930,081	10,322,075	224,881,906
22	Surplus Sales	$	(7,761,189)	(17,822,923)	(20,964,875)	(14,089,689)	(21,263,175)	(205,529,286)
23	Expense Adjustment (@16.84)	$	(344,816)	(1,213,726)	(1,973,513)	(235,356)	(182,377)	(11,964,517)
24	Sub-Total	$	14,373,113	12,949,948	9,807,475	7,372,954	(562,644)	126,970,034
25								
26	BASE:							
27	Fuel Expense - Coal	$	8,442,408	8,726,608	8,453,508	7,372,808	7,282,408	95,138,364
28	Fuel Expense - Danskin	$	264,400	273,100	272,200	257,500	273,600	3,257,200
29	Fuel Expense - Bennett Mountain	$	6,100	99,700	51,100	26,300	51,800	1,194,300
30	Non-Firm Purchases	$	603,000	841,100	387,500	84,000	72,800	11,842,800
31	Surplus Sales	$	(1,419,600)	(3,443,800)	(5,889,800)	(7,776,100)	(8,155,400)	(64,162,300)
32	Cloud Seeding Expense	$	167,423	167,423	167,423	167,423	167,423	1,004,538
33	Cloud Seeding Benefit	$	(316,667)	(316,667)	(316,667)	(316,667)	(316,667)	(1,900,002)
34	Sub-Total	$	7,747,064	6,347,464	3,125,264	(184,736)	(624,036)	46,374,900
35								
36	Change From Base	$	6,626,049	6,602,484	6,682,211	7,557,690	61,392	80,595,134
37	Emission Allowance Sales Credit	$	0	0	0	0	0	(49,712,488)
38	Sub-Total		6,626,049	6,602,484	6,682,211	7,557,690	61,392	30,882,646
39								
40	Deferral (Shared and Allocated)	$	5,611,601	5,591,644	5,659,164	6,400,608	51,993	26,154,513
41								
42	**QF Deferral**							
43	Actual (includes Net Metering)	$	3,123,690	3,218,089	2,401,300	2,133,362	2,117,273	52,320,147
44	Base	$	3,239,593	3,483,863	3,036,410	2,957,595	2,307,604	54,059,005
45								
46	Change From Base	$	(115,903)	(265,774)	(635,110)	(824,233)	(190,331)	(1,738,858)
47	Deferral (Allocated)	$	(109,065)	(250,093)	(597,639)	(775,603)	(179,101)	(1,636,265)
48								
49	Settlement Agreement (ON 29600)	$	0	0	0	0	0	(1,608,333)
50	Bennett Mtn. Credit (ON 29790)	$	0	0	0	0	0	(7,972)
51	**Total Deferral** (-6+40+47+49+50)	$	7,789,763	7,901,338	7,810,203	8,213,891	2,308,524	42,606,784
52								
53	**Principal Balances**							
54	Beginning Balance	$	8,583,066	16,372,829	24,274,166	32,084,369	40,298,260	
55	Amount Deferred	$	7,789,763	7,901,338	7,810,203	8,213,891	2,308,524	42,606,784
56	Ending Balance	$	16,372,829	24,274,166	32,084,369	40,298,260	42,606,784	
57								
58	**Interest Balances**							
59	Accrual thru Prior Month	$	(795,562)	(774,105)	(733,193)	(672,508)	(592,297)	
60	Interest @ 3% per Year	$	21,458	40,932	60,685	80,211	100,746	64,647
61	Prior Month's Interest Adj.	$	(1)	(20)	0	0	51	(556,147)
62	Total Current Month Interest	$	21,457	40,912	60,685	80,211	100,797	(491,500)
63	Interest Accrued to Date	$	(774,105)	(733,193)	(672,508)	(592,297)	(491,500)	
64	**Balance (True-Up & Interest)**	$	15,598,724	23,540,973	31,411,862	39,705,963	42,115,284	**42,115,284**
65								
66	**True-Up of the True-Up**							
67	True-Up Revenues (Collections)	$	(1,126,013)	(1,282,021)	(1,400,463)	(1,298,217)	(1,127,125)	(7,834,824)
68								
69	Beginning Balance	$	(14,029,877)	(12,938,939)	(11,689,265)	(10,318,026)	(9,045,604)	24,513,298
70	Adjustments:							
71	2005-06 PCA Transfer (ON 30047)	$	0	0	0	0	0	(39,513,704)
72	Tax Settlement True-Up (ON 29789)	$	0	0	0	0	0	(333,015)
73	0	$	0	0	0	0	0	0
74	Sub-Total	$	(14,029,877)	(12,938,939)	(11,689,265)	(10,318,026)	(9,045,604)	(15,333,421)
75	Interest @ 3% per Year	$	(35,075)	(32,347)	(29,223)	(25,795)	(22,614)	
76	Revenue Applied to Interest	$	(35,075)	(32,347)	(29,223)	(25,795)	(22,614)	(442,496)
77	Revenue Applied to Balance	$	(1,090,938)	(1,249,674)	(1,371,240)	(1,272,422)	(1,104,511)	(7,392,328)
78	**True-Up of the True-Up Balance**	$	(12,938,939)	(11,689,265)	(10,318,026)	(9,045,604)	(7,941,093)	**(7,941,093)**
79								
80	Note: Negative amounts indicate benefit to ratepayers							

Attachment D
Case No. IPC-E-07-10
Staff Comments

Summary of PCA Components
IPC-E-07-10
Staff Case

90.0% Sharing Percentage

94.1% Idaho Allocation

Description	Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	PCA Rates (¢/kWh)
Forecast (2007-2008)	28,318,176	1,670,772	2,664,740	23,982,663	**0.1888**
True Up (2006-2007)					
Revenue from Forecast Rate	19,704,842			19,704,842	
Non-QF Power Supply Cost Difference	92,559,648	5,461,019	8,709,863	78,388,766	
Load Growth Adjustment	(11,964,517)	(705,907)	(1,125,861)	(10,132,749)	
QF Power Supply Cost Difference	(1,738,860)	(102,593)		(1,636,267)	
Other Limited Term Adjustments:					
Emission Allowance Sales Credit (O.N. 30041)	(49,712,488)	(2,933,037)	(4,677,945)	(42,101,506)	
Settlement Agreement (O.N. 29600)	(1,608,333)			(1,608,333)	
Bennett Mountain Credit (O.N. 29790)	(7,972)			(7,972)	
Interest During Deferral Period	(491,500)			(491,500)	
Sub-Total	46,740,820	1,719,483	2,906,057	42,115,280	
Future Emission Allowance Tax Benefit (O.N. 30041)	(27,025,013)			(27,025,013)	
Sub-Total	19,715,807	1,719,483	2,906,057	15,090,267	**0.1120**
True Up of the True Up					
Amount Carried Forward	24,513,298			24,513,298	
Other Limited Term Adjustments:					
2005-2006 PCA Transfer (O.N. 30047)	(39,513,704)			(39,513,704)	
Tax Settlement True Up (O.N. 29789)	(333,015)			(333,015)	
Interest During Amortization	(442,496)			(442,496)	
Collections from True Up Rate	7,834,823			7,834,823	
Sub-Total	(7,941,094)	0	0	(7,941,094)	**(0.0589)**
Total Power Cost Adjustment (PCA)	40,092,889	3,390,256	5,570,797	31,131,836	**0.2419**

Attachment E
Case No. IPC-E-07-10
Staff Comments
5/14/07

IPC-E-07-10
Idaho Power Company
Summary of Revenue Impact
State of Idaho
Normalized 12-Months Ending December 31, 2005
6/1/06 Base

Base Rates to 6/1/07 PCA

Line No	Tariff Description	(1) Rate Sch. No.	(2) 2005 Avg. Number of Customers	(3) 2005 Sales Normalized (kWh)	(4) 06/01/06 Base Revenue	(5) 06/01/07 PCA Adjustment	(6) Total Revenue	(7) Average ¢/kWh	(8) Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1/4/5	359,802	4,503,865,230	266,728,029	10,894,850	277,622,879	6.164	4.08%
2	Small General Service	7	30,899	218,605,825	16,039,937	528,807	16,568,744	7.579	3.30%
3	Large General Service	9	20,998	3,227,118,622	130,354,522	7,806,400	138,160,922	4.281	5.99%
4	Dusk to Dawn Lighting	15	-	5,933,906	938,956	14,354	953,310	16.065	1.53%
5	Large Power Service	19	115	2,056,658,504	63,551,457	4,975,057	68,526,514	3.332	7.83%
6	Agricultural Irrigation Service	24/25	15,085	1,574,100,117	71,787,672	3,807,748	75,595,420	4.802	5.30%
7	Unmetered General Service	40	2,310	16,202,707	873,323	39,194	912,517	5.632	4.49%
8	Street Lighting	41	129	18,704,636	1,954,043	45,247	1,999,290	10.689	2.32%
9	Traffic Control Lighting	42	72	7,842,173	270,087	18,970	289,057	3.686	7.02%
10	*Total Uniform Tariffs*		429,410	11,629,031,720	552,498,026	28,130,627	580,628,653	4.993	5.09%
	Special Contracts:								
11	Micron	26	1	673,760,250	17,917,745	1,629,826	19,547,571	2.901	9.10%
12	J R Simplot	29	1	187,632,199	4,645,191	453,882	5,099,073	2.718	9.77%
13	DOE	30	1	204,738,943	5,162,163	495,264	5,657,427	2.763	9.59%
14	*Total Special Contracts*		3	1,066,131,392	27,725,099	2,578,972	30,304,071	2.842	9.30%
15	***Total Idaho Retail Sales***		429,413	12,695,163,112	580,223,125	30,709,599	610,932,724	4.812	5.29%