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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 15, 2005	CASE NO. IPC-E-04-09

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

GREGORY W. SAID

Q. Please state your name and business address.

A. My name is Gregory W. Said and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company as the Manager of Revenue Requirement in the Pricing and Regulatory Services Department.

Q. Please describe your educational background.

A. In May of 1975, I received a Bachelor of Science Degree in Mathematics with honors from Boise State University. In 2003, I attended the Public Utility Executives Course at the University of Idaho.

Q. Please describe your work experience with Idaho Power Company.

A. I became employed by Idaho Power Company in 1980 as an analyst in the Resource Planning Department. In 1985, the Company applied for a general revenue requirement increase. I was the Company witness addressing power supply expenses.

In August of 1989, after nine years in the Resource Planning Department, I was offered and I accepted a position in the Company's Rate Department. With the Company's application for a temporary rate increase in 1992, my responsibilities as a witness were expanded. While I continued to be the Company witness concerning power supply expenses, I also sponsored the Company's rate computations and proposed tariff schedules in that case.

Because of my combined Resource Planning and Rate Department experience, I was asked to design a Power Cost Adjustment (PCA) which would impact customers' rates based upon changes in the Company's net power supply expenses. I presented my recommendations to the Idaho Public Utilities Commission (IPUC) in 1992 at which time the IPUC established the PCA as an annual adjustment to the Company's rates. I have sponsored the Company's annual PCA adjustment in each of the years 1996 through 2003.

In 1996, I was promoted to Director of Revenue Requirement.

Q. Are you the same Gregory Said that presented testimony in the Company's general revenue requirement case (IPUC Case No. IPC-E-03-13)?

A. Yes. In my testimony in the Company's general revenue requirement case, I discussed changes in loads and resources since the Company's last general revenue requirement case and the impact of those changes on the Company's power supply expenses. I sponsored the exhibits that provided the basis for determining the Company's normalized net power supply expenses for ratemaking purposes. I discussed how the new normalized power supply expenses impact future PCA computations until the Company's next general revenue requirement case.

Q. Did you recommend any PCA computational changes for the establishment of the new PCA regression formula as part of the Company's general revenue requirement filing?

A. Yes. I recommended that three PCA computational factors be updated as a result of the review of power supply expenses. First, for PCA projection calculations, a new normalized base PCA rate was calculated. Second, a new Idaho jurisdictional percentage was calculated. Third a new expense adjustment rate to be applied to load growth (EARG) or decline was calculated.

Q. Did you also present a non-computational recommendation with regard to the PCA in your testimony in Case No. IPC-E-03-13?

A. Yes. I recommended that the PCA recovery period be moved from a May 16 through May 15 period to a June 1 through May 31 time period. No other changes to PCA time frames would be required. PCA projection and true-up computations would still be based upon an April 1 through March 31 time frame and the Company would still file its PCA request by April 15 each year.

Q. Based upon your recommendation that this year's PCA become effective on June 1, 2004, what do you recommend as the PCA rate from May 16, 2004 through May 31, 2004?

A. Rather than having two rate adjustments within fifteen days, I recommend that the current PCA rate be extended throughout May 2004.

Q. Are tariff changes required to accommodate your proposal?

A. Yes. Exhibit 1 contains the tariff changes required to accommodate my proposal.

Q. What is the impact of using a June 1, 2004, PCA effective date, as recommended in your testimony in the IPC-E-03-13 general revenue requirement case and discussed previously in this testimony?

A. If the current PCA rates become effective on June 1, 2004 instead of May 16, 2004, the Company will collect at the 2003/2004 PCA rate for an additional one-half month. However, the True-up of the True-up provision of the PCA will distribute any over-collection or under-collection from this event back to the Company's customers as a component of the 2005/2006 PCA. Additionally, the Company has recommended that any potential rate change from the general revenue requirement case become effective on the same date as the 2004/2005 PCA.

Q. Did the IPUC receive any testimony in opposition of the changes you recommended in Case No. IPC-E-

03-13?

A. Yes. Staff opposed my recommendation regarding computation of the EARG. The issue of the appropriate EARG was removed from the general revenue requirement case forum and the determination of the EARG will occur later this year. None of my other PCA recommendations were opposed.

Q. What is this year's projection of PCA expenses?

A. Based upon the updated PCA constants, the projection of PCA expenses for the period April 1, 2004 through March 31, 2005 is $129,823,425. This amount is $35,722,268 more than the $94,101,157 normalized level of PCA expenses as filed in Case No. IPC-E-03-13.

Q. What is the basis for the projection of April 1, 2004 through March 31, 2005 PCA expenses?

A. The IPUC, in Order No. 24806 issued in Case No. IPC-E-92-25, the proceeding which created the PCA, adopted a natural logarithmic function of projected April through July Brownlee runoff to compute the projection of April through March PCA expenses. Assuming that the derivation of that equation will be updated as a result of the Company's filing in Case No. IPC-E-03-13, the new PCA regression equation is:

Annual PCA expense = $1,140,615,325
- $ 70,685,112 * ln (Brownlee runoff)
+ $ 46,413,057

Details of the data underlying the PCA regression equation are contained in Exhibit 2. Qualifying Facilities ("QF") purchase expenses were updated and are included in the projection computation.

In this formula, the $1,140,615,325 is the updated constant that represents the prediction of annual net power supply expense that would occur if there was zero April through July Brownlee runoff. For each unit increase in the natural logarithm of the Brownlee runoff data the projection of annual power supply expenses will be reduced by $70,685,112, the second of the updated constants in the equation above. The $46,413,057 is the updated constant for QF purchase expense.

Q. What is the April through July Brownlee runoff forecast that you used to arrive at the projection of PCA expenses?

A. The National Weather Service's Northwest River River Forecast Center (NWRFC), in its April 1 forecast, projected April through July Brownlee runoff to be 3.13 million acre-feet. Inserting this value into the equation results in a projection of net PCA expenses of $129,823,425 for the period April 1, 2004 through March 31,

2005. This amount is $35,722,268 more than the normalized level of PCA expenses of $94,101,157. The Brownlee runoff information supplied by the NWRFC is contained on Exhibit 3. The Brownlee Reservoir inflow appears on page 2 of 5 of Exhibit 3.

Q. You have stated that the projected net PCA expenses are more than the normalized level of PCA expenses by $35,722,268. What is the rate adjustment associated with the projected increase in PCA expenses of $35,722,268 from the normalized level of PCA expenses?

A. The updated normalized PCA expense of $94,101,157, divided by the updated normalized system firm sales of 12,863,484 Megawatt-hours, is used to arrive at the normalized base power cost of 0.7315 cents per kilowatt-hour. For the period April 1, 2004 through March 31, 2005, the projected power cost of serving firm loads is 1.0092 cents per kilowatt-hour which is computed by dividing the projected incremental PCA expense of $35,722,268 by the 12,863,484 Megawatt-hours normalized system firm sales. The Company adjusts its rates by 90 percent of the difference between the projected power cost of serving firm loads (1.0092 cents per kilowatt-hour) and the normalized base power cost (0.7315 cents per kilowatt-hour). Restated, this year's computation is (.9)(1.0092-0.7315)=0.2499. The resulting adjustment is a 0.2499 cents per kilowatt-hour increase from the normalized base power cost.

Q. Please describe the True-Up required from the comparison of the April 1, 2003 through March 31, 2004 actual results to last year's projections.

A. The PCA True-Up deferral for the year April 1, 2003 through March 31, 2004 is shown on Exhibit 4. This sheet compares the actual results to last year's projections, month by month, with the differences accumulated in a deferred expense account. Interest has been applied to the deferred expense account monthly. The balance in the deferred expense account at the end of March 2004 was $44,285,289 as shown on Exhibit 4. This is the amount that was under-collected during the PCA year. The Accounting Department has advised me that the deferral will be amortized during the current PCA year.

Q. How is the $44,285,289 from Exhibit 4 reflected in the True-Up portion of the PCA?

A. In accordance with Order No. 29334 from Case No. IPC-E-03-05, the True-Up component is calculated by dividing the deferred expense balance of $44,285,289 by the Company's "best estimate of the total Idaho jurisdictional sales that will be made during the ensuing PCA year" (Exhibit 5, page 4, paragraph 2). The Company has filed updated normalized Idaho jurisdictional firm sales of 12,096,838 Megawatt-hours as part of the IPC-E-03-13 general revenue requirement case and believes this is the best estimate for Megawatt-hours sales during the 2004/2005 PCA year. The result of dividing the deferred expense balance by the Idaho jurisdictional firm sales is 0.3661 cents per kilowatt-hour, which is the True-Up portion of the PCA.

Q. Were there any decisions made by the IPUC in Order No. 29334 that will require adjustments to the 2004/2005 PCA rate?

A. Yes. Item 2 in the Stipulation approved by the Commission in Order No. 29334 addressed a "True-up of the True-up." Item 4 in the Stipulation addressed class specific adjustments.

Q. How will the True-up of the True-up be reflected in this year's PCA?

A. The Company collected all but $556,693 of the $38,658,298 True-up deferral balance from last year. Dividing the $556,693 by the Idaho jurisdictional sales value of 12,096,838 Megawatt-hours results in 0.0046 cents per kilowatt-hour as the True-up of the True-up rate.

Q. Please describe the class specific adjustments contained in Item 4 of the Stipulation.

A. The Company will make three class specific rate adjustments to the 2004/2005 PCA rate. The three classes and their respective adjustment credits are: 1) Schedule 7, Small Commercial, -0.0189 cents per kilowatt hour; 2) Schedule 19, Industrial -0.0222 cents per kilowatt hour; and 3) Schedule 24, Irrigation, -0.0811 cents per kilowatt hour. The calculation of the adjustments is shown on page 5 of Exhibit 5.

Q. What is the PCA rate as a result of (1) the adjustment for the 2004/2005 Projected power cost of serving firm loads, (2) the 2003/2004 True-Up portion of the PCA, and 3) the True-up of the 2002/2003 True-up?

A. The Company's PCA rate for the 2004/2005 PCA year is 0.6206 cents per kilowatt-hour. The rate is comprised of: 1) the 0.2499 cents per kilowatt-hour adjustment for 2004/2005 projected power cost of serving firm loads, 2) the 0.3661 cents per kilowatt-hour for the 2003/2004 True-Up portion of the PCA, and 3) the 0.0046 cents per kilowatt-hour for the True-up of the 2002/2003 True-up. The components used to calculate the 0.6206 cents per kilowatt-hour are shown in Exhibit 6, the Company's proposed Schedule 55.

Q. How does the new PCA rate of 0.6206 cents per kilowatt-hour compare to the existing PCA rate?

A. The 2004/2005 PCA rate of 0.6206 cents per kilowatt-hour is 0.0167 cents per kilowatt-hour greater than the 0.6039 cents per kilowatt-hour PCA rate that existed for all classes except Schedule 7, Schedule 19 and Schedule 24.

Q. In light of the Company's pending general revenue requirement case and an anticipated general rate increase coming from that general revenue requirement case, does the Company have an additional PCA recommendation this year?

A. Yes. The Company has frequently stated that its hope was for a Brownlee runoff forecast sufficient to provide for a PCA reduction to coincide with the general rate increase. Unfortunately, that did not occur. Rather than create additional upward pressure on rates, the Company proposes to keep the overall PCA rate at the same level as last year, 0.6039 cents per kilowatt-hour. To accomplish this, the True-up component rate would be adjusted down by 0.0167 cents per kilowatt-hour. The three customer classes previously identified will still experience PCA rate reductions, in addition to the reduction from their current rates, to the 2004/2005 PCA rate minus their class-specific credits.

Q. Will the Company forfeit the additional revenue to which it is entitled?

A. No. Based upon the difference between the entitled rate of 0.6206 cents per kilowatt-hour and the proposed retention of the 0.6039 cents per kilowatt-hour rate, the Company would under-collect its entitled expense by $2,020,172 ((0.6206-0.6039) cents per kilowatt-hour)*12,096,838 Megawatt-hours). Because there is now a

True-up of the True-up, any under-collection of True-up amounts will be captured next year. In other words, with the beginning balance for the True-up of the True-up set at $44,841,981 ($44,285,289+$556,693) and PCA True-up component rates established to recover $42,818,861, at PCA year end, the Company will have under-collected $2,020,172, which would flow into next year's True-up of the True-up balance. The Company is proposing this unique rate treatment to avoid "pancaking" rate increases in 2004.

Q. What are the 2004/2005 PCA rates for Schedule 7, Schedule 19 and Schedule 24 customers?

A. Because of the pre-established credits, the Schedule 7 PCA rate will be 0.5850 cents per kilowatt-hour (0.6039-0.0189), the Schedule 19 PCA rate will be 0.5817 cents per kilowatt-hour (0.6039-0.0222), and the Schedule 24 PCA rate will be 0.5228 cents per kilowatt-hour(0.6039-0.0811).

Q. What percentage decrease from existing rates including PCA, to new rates including PCA, will these classes see as an offset to any general rate increase?

A. Exhibit 7 details the percentage rate change that all customer classes will see as an offset to rate increases ordered in the general revenue requirement case. Schedule 7 customer will see a 3.66% decrease, Schedule 19 customers will see a 6.66% decrease and Schedule 24 customers will see a 15.75% decrease. All other customer classes will see no change as a result of the new PCA.

Q. Are you aware that the Idaho Supreme Court has reversed the IPUC's decision in Case No. IPC-E-01-34 and ruled that Idaho Power Company is entitled to the collection of lost revenues?

A. Yes.

Q. Have you included any amounts in this year's PCA to reflect the Supreme Court decision?

A. No.

Q. Why not?

A. Counsel for the Company has advised me that at the time of the filing of my testimony in this proceeding, the decision of the Idaho Supreme Court is not final and the matter has not been remanded to the IPUC.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-09

IDAHO POWER COMPANY

EXHIBIT NO. 1

G. SAID

Original & Legislative Tariff Schedules

SCHEDULE 1
RESIDENTIAL SERVICE
(Continued)

RESIDENTIAL SPACE HEATING

All space heating equipment to be served by the Company's system shall be single phase equipment approved by Underwriters' Laboratories, Inc., and the equipment and its installation shall conform to all National, State and Municipal Codes and to the following:

Individual resistance-type units for space heating larger than 1,650 watts shall be designed to operate at 240 or 208 volts, and no single unit shall be larger than 6 kW. Heating units of two kW or larger shall be controlled by approved thermostatic devices. When a group of heating units, with a total capacity of more than 6 kW, is to be actuated by a single thermostat, the controlling switch shall be so designed that not more than 6 kW can be switched on or off at any one time. Supplemental resistance-type heaters, that may be used with a heat exchanger, shall comply with the specifications listed above for such units.

MONTHLY CHARGE

The Monthly Charge is the sum of the Customer and the Energy Charges at the following rates:

Customer Charge
$2.51 per meter per month

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
4.9303¢	0.6039¢	5.5342¢

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge and the Energy Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 7
SMALL GENERAL SERVICE
(Continued)

MONTHLY CHARGE (Continued)

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge and the Energy Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

SECONDARY SERVICE (Continued)

Facilities Charge
None

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, and the Energy Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

PRIMARY SERVICE

Customer Charge
$85.58 per meter per month

Basic Charge
$0.77 per kW of Basic Load Capacity

Demand Charge
$2.65 per kW for all kW of Demand

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.1308¢	0.6039¢	2.7347¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

TRANSMISSION SERVICE

Customer Charge
$85.58 per meter per month

Basic Charge
$0.39 per kW of Basic Load Capacity

Demand Charge
$2.57 per kW for all kW of Demand

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.0833¢	0.6039¢	2.6872¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 15
DUSK TO DAWN CUSTOMER LIGHTING
(Continued)

MONTHLY CHARGES (Continued)

FLOOD LIGHTING

High Pressure Sodium Vapor	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
200 Watt	19,800	$17.18	$0.41	$17.59
400 Watt	45,000	$25.63	$0.83	$26.46
Metal Halide				
400 Watt	28,800	$28.64	$0.83	$29.47
1000 Watt	88,000	$52.28	$2.07	$54.35

* This Power Cost Adjustment is computed as provided in Schedule 55.

2. The Monthly Charge for New Facilities to be installed, such as overhead (or equivalent) secondary conductor, poles, anchors, etc., shall be 1.75 percent of the estimated installed cost thereof.

3. The Company may provide underground service from existing secondary facilities when the Customer pays the estimated nonsalvable cost of underground facilities.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

SECONDARY SERVICE (Continued)

Facilities Charge
None

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, and the Energy Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

PRIMARY SERVICE

Customer Charge
$85.71 per meter per month

Basic Charge
$0.77 per kW of Basic Load Capacity

Demand Charge
$2.65 per kW for all kW of Billing Demand

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.0839¢	0.8217¢	2.9056¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE

Customer Charge
$85.71 per meter per month

Basic Charge
$0.39 per kW of Basic Load Capacity

Demand Charge
$2.57 per kW for all kW of Billing Demand

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.0375¢	0.8217¢	2.8592¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 24
IRRIGATION SERVICE
(Continued)

FACILITIES BEYOND THE POINT OF DELIVERY (Continued)

In the event the Customer requests the Company to remove or reinstall or change Company-owned Facilities Beyond the Point of Delivery, the Customer shall pay to the Company the "non-salvable cost" of such removal, reinstallation or change. Non-salvable cost as used herein is comprised of the total original costs of materials, labor and overheads of the facilities, less the difference between the salvable cost of material removed and removal labor cost including appropriate overhead costs.

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 85 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 85 percent and dividing by the actual Power Factor.

MONTHLY CHARGE

The Monthly Charge is the sum of the Customer, the Demand, the Energy, and the Facilities Charges at the following rates.

SECONDARY SERVICE

Customer Charge

$10.07 per meter per month	Irrigation Season
$ 2.50 per meter per month	Out of Season

Demand Charge

$3.58 per kW of Billing Demand	Irrigation Season
No Demand Charge	Out of Season

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.8416¢	1.3159¢	4.1575¢ per kWh for all kWh Irrigation Season
3.6172¢	1.3159¢	4.9331¢ per kWh for all kWh Out of Season

Facilities Charge
None

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Demand Charge, and the Energy Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

SCHEDULE 24
IRRIGATION SERVICE
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE

Customer Charge

$85.61 per meter per month	Irrigation Season
$ 2.50 per meter per month	Out of Season

Demand Charge

$3.37 per kW of Billing Demand	Irrigation Season
No Demand Charge	Out of Season

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.7021¢	1.3159¢	4.0180¢ per kWh for all kWh Irrigation Season
3.4396¢	1.3159¢	4.7555¢ per kWh for all kWh Out of Season

Facilities Charge

The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

PAYMENT

All monthly billings for Electric Service supplied hereunder are payable upon receipt, and become past due 15 days from the date on which rendered. (For any agency or taxing district which has notified the Company in writing that it falls within the provisions of Idaho Code § 67–2302, the past due date will reflect the 60 day payment period provided by Idaho Code § 67–2302.)

Deposit. A deposit payment for irrigation Customers is required under the following conditions:

1. Existing Customers: Customers who have two or more reminder notices for nonpayment of Electric Service during a 12-month period or who have service disconnected for non-payment will be required to pay a deposit, or provide a guarantee of payment from a bank or financial institution acceptable to the Company. A reminder notice is issued approximately 45 days after the bill issue date if the balance owing for Electric Service totals $100 or more or approximately 105 days after the bill issue date for Customers meeting the provisions of Idaho Code § 67–2302. The deposit for a specific installation will be computed as follows:

SCHEDULE 25
IRRIGATION SERVICE – TIME-OF-USE
PILOT PROGRAM
(OPTIONAL)
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the Customer, the TOU Metering, the Demand, the Energy, and the Facilities Charges at the following rates.

SECONDARY SERVICE

Customer Charge

$10.07 per meter per month	Irrigation Season
$ 2.50 per meter per month	Out of Season

TOU Metering Charge

$3.00 per meter per month	Irrigation Season
No TOU Meter Charge	Out of Season

Demand Charge

$3.58 per kW of Billing Demand	Irrigation Season
No Demand Charge	Out of Season

Energy Charge

	Base Rate	Power Cost Adjustment*	Effective Rate*
	IN-SEASON		
On-Peak	4.9728¢	1.3159¢	6.2887¢ per kWh for all kWh
Mid-Peak	2.8416¢	1.3159¢	4.1575¢ per kWh for all kWh
Off-Peak	1.4208¢	1.3159¢	2.7367¢ per kWh for all kWh
	OUT-OF-SEASON		
	3.6172¢	1.3159¢	4.9331¢ per kWh for all kWh

Facilities Charge
None

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the TOU Metering Charge, the Demand Charge, and the Energy Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

SCHEDULE 25
IRRIGATION SERVICE – TIME-OF-USE
PILOT PROGRAM
(OPTIONAL)
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE

Customer Charge

$85.61 per meter per month	Irrigation Season
$ 2.50 per meter per month	Out of Season

TOU Metering Charge
None

Demand Charge

$3.37 per kW of Billing Demand	Irrigation Season
No Demand Charge	Out of Season

Energy Charge

	Base Rate	Power Cost Adjustment*	Effective Rate*
	IN-SEASON		
On-Peak	4.7287¢	1.3159¢	6.0446¢ per kWh for all kWh
Mid-Peak	2.7021¢	1.3159¢	4.0180¢ per kWh for all kWh
Off-Peak	1.3511¢	1.3159¢	2.6670¢ per kWh for all kWh
	OUT-OF-SEASON		
	3.4396¢	1.3159¢	4.7555¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in Schedule 55.

IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
SCHEDULE 26
FOR
MICRON TECHNOLOGY, INC.
BOISE, IDAHO

SPECIAL CONTRACT DATED SEPTEMBER 1, 1995
(Continued)

MONTHLY ENERGY CHARGE

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
12.783	6.039	18.822 mills per kWh for all energy

*This Power Cost Adjustment is computed as provided in Schedule 55.

MONTHLY O & M CHARGES

0.4 percent of total cost of Substation Facilities.

CONSERVATION PROGRAMS RECOVERY CHARGE

$5,703 per month

IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
SCHEDULE 29
J. R. SIMPLOT COMPANY
POCATELLO, IDAHO

SPECIAL CONTRACT DATED AUGUST 27, 1973

MONTHLY CONTRACT RATE

Demand Charge
$6.68 per kW of Billing Demand (1)

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
14.080	6.039	20.119 mills per kWh for all energy (2)

Minimum Charge

The minimum monthly charge shall be the amount computed in accordance with Paragraph 5.1, but not less $100,188.61 for any month during the effective term of this Agreement.

*This Power Cost Adjustment is computed as provided in Schedule 55.

CONSERVATION PROGRAMS RECOVERY CHARGE

$5,061 per month

Contract Changes

(1) Contract Paragraph No 5.1(a).

No Change

(2) Contract Paragraph No. 5.1(b)
Change 33.450 mills to 20.119 mills

(3) Contract Paragraph No. 5.2.

No Change

IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
SCHEDULE 30
FOR
UNITED STATES DEPARTMENT OF ENERGY
IDAHO OPERATIONS OFFICE

SPECIAL CONTRACT DATED MAY 16, 2000
CONTRACT NO. GS-OOP-99-BSD-0124

AVAILABILITY

This schedule is available for firm retail service of electric power and energy delivered for the operations of the Department of Energy's facilities located at the Idaho National Engineering Laboratory site, as provided in the Contract for Electric Service between the parties.

MONTHLY CHARGE

The monthly charge for electric service shall be the sum of the Demand, Energy, and Conservation Programs Recovery Charges determined at the following rates:

1. Demand Charge:

$5.10 per kW of Billing Demand Per Month

2. Energy Charge:

Base Rate	Power Cost Adjustment*	Effective Rate*
13.404	6.039	19.443 mills per kWh for all energy

3. Conservation Programs Recovery Charge

$3,521 per month

*This Power Cost Adjustment is computed as provided in Schedule 55.

SPECIAL CONDITIONS

1. Billing Demand:

The Billing Demand shall be the average kW supplied during the 30-minute period of maximum use during the month.

2. Power Factor Adjustment:

When the Power Factor is less than 95 percent during the 30-minute period of maximum load for the month, Company may adjust the measured Demand to determine the Billing Demand by multiplying the measured kW of Demand by 0.95 and dividing by the actual Power Factor.

IDAHO POWER COMPANY
AGREEMENT FOR SUPPLY OF SHIELDED
STREET LIGHTING SERVICE
SCHEDULE 32
FOR THE CITY OF KETCHUM, IDAHO

SPECIAL CONTRACT DATED JUNE 12, 2001

MONTHLY CHARGE PER LAMP

High Pressure Sodium Vapor	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
70 Watt	6,400	$ 7.07	$0.14	$ 7.21
100 Watt	9,500	$ 7.64	$0.21	$ 7.85
200 Watt	22,000	$ 9.59	$0.41	$10.00

*This Power Cost Adjustment is computed as provided in Schedule 55.

ADDITIONAL MONTHLY RATE

For Company-owned poles installed after October 5, 1964 required to be used for street lighting only:

Wood pole ....$1.71 per pole
Steel pole ....$6.80 per pole

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 40
UNMETERED GENERAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Idaho where existing secondary distribution facilities of adequate capacity, phase and voltage are available adjacent to the Customer's Premises and the only investment required by the Company is an overhead service drop.

APPLICABILITY

Service under this schedule applies to Electric Service for the Customer's single- or multiple-unit loads up to 1,800 watts per unit where the size of the load and period of operation are fixed and, as a result, actual usage can be accurately determined. Service may include, but is not limited to, street and highway lighting, security lighting, telephone booths and CATV power supplies which serve line amplifiers. Facilities to supply service under this schedule shall be installed so that service cannot be extended to the Customer's loads served under other schedules. Service under this schedule is not applicable to shared or temporary service, or to the Customer's loads on Premises which have metered service.

SPECIAL TERMS AND CONDITIONS

The Customer shall pay for all Company investment, except the overhead service drop, required to provide service requested by the Customer. The Customer is responsible for installing, owning and maintaining all equipment, including necessary underground circuitry and related facilities to connect with the Company's facilities at the Company designated Point of Delivery. If the Customer's equipment is not properly maintained, service to the specific equipment will be terminated.

Energy used by CATV power supplies which serve line amplifiers will be determined by the power supply manufacturer's nameplate input rating assuming continuous operation.

The Company is only responsible for supplying energy to the Point of Delivery and, at its expense, may check energy consumption at any time.

MONTHLY CHARGE

The average monthly kWh of energy usage shall be estimated by the Company, based on the Customer's electric equipment and one-twelfth of the annual hours of operation thereof. Since the service provided is unmetered, failure of the Customer's equipment will not be reason for a reduction in the Monthly Charge. The Monthly Charge shall be computed at the following rate:

Base Rate	Power Cost Adjustment*	Effective Rate*
5.68¢	0.604¢	6.284¢ per kWh for all kWh

Minimum Charge
$1.50 per month

*This Power Cost Adjustment is computed as provided in Schedule 55.

SCHEDULE 41
STREET LIGHTING SERVICE

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Idaho where street lighting wires and fixtures can be installed on the Company's existing distribution facilities.

APPLICABILITY

Service under this schedule is applicable to service required by municipalities or agencies of federal, state, or county governments for the lighting of public streets, alleys, public grounds, and thoroughfares. Street lighting lamps will be energized each night from dusk until dawn.

SERVICE LOCATION AND PERIOD

Street lighting facility locations, type of unit and lamp sizes, as changed from time to time by written request of the Customer and agreed to by the Company, shall be as shown on an Exhibit A for each Customer receiving service under this schedule. The in-service date for each street lighting facility will be maintained on the Exhibit A.

The minimum service period for any street lighting facility is 10 years. The Company, upon written notification from the Customer, will remove a street lighting facility:

1. At no cost to the Customer, if such facility has been in service for no less than the minimum service period;

2. Upon payment to the Company of the removal cost, if such facility has been in service for less than the minimum service period.

"A" - OVERHEAD LIGHTING - COMPANY-OWNED SYSTEM

The facilities required for supplying service, including fixture, lamp, control relay, mast arm or mounting on an existing utility pole, and energy for the operation thereof, are supplied, installed, owned and maintained by the Company. All necessary repairs, maintenance work, including group lamp replacement and glassware cleaning, will be performed by the Company during the regularly scheduled working hours of the Company on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements.

MONTHLY CHARGE PER LAMP

High Pressure Sodium Vapor	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
100 Watt	8,550	$ 6.37	$0.25	$ 6.62
200 Watt	19,800	$ 7.44	$0.48	$ 7.92
400 Watt	45,000	$10.60	$1.00	$11.60

*This Power Cost Adjustment is computed as provided in Schedule 55.

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

ADDITIONAL MONTHLY RATE

For Company-owned poles installed after October 5, 1964 required to be used for street lighting only:

Wood pole ....$1.71 per pole
Steel pole ....$6.80 per pole

UNDERGROUND CIRCUITS will be installed when the Customer pays the estimated cost difference between overhead and underground, or the Customer agrees to pay a monthly charge of 1.75 percent of the estimated cost difference.

"B" - CUSTOMER-OWNED SYSTEM

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed and owned by the Customer.

Service supplied by the Company includes operation of the system, energy, lamp renewals, cleaning of glassware, and replacement of defective ballasts and photocells which are standard to the Company-owned street light units. Service does not include the labor or material cost of replacing cables, standards, broken glassware or fixtures, or painting or refinishing of metal poles.

MONTHLY CHARGE PER LAMP

High Pressure Sodium Vapor	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
100 Watt	8,550	$3.45	$0.25	$ 3.70
200 Watt	19,800	$4.75	$0.48	$ 5.23
250 Watt	24,750	$5.69	$0.63	$ 6.32
400 Watt	45,000	$7.87	$1.00	$ 8.87

*This Power Cost Adjustment is computed as provided in Schedule 55.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 41
STREET LIGHTING SERVICE

NO NEW SERVICE
(Continued)

MONTHLY CHARGE PER LAMP

	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
Mercury Vapor				
175 Watt	7,700	$ 6.99	$0.42	$ 7.41
400 Watt	18,800	$11.59	$0.98	$12.57
High Pressure Sodium Vapor				
150 Watt	13,800	$ 6.89	$0.36	$ 7.25
250 Watt	24,750	$ 8.42	$0.63	$ 9.05

*This Power Cost Adjustment is computed as provided in Schedule 55.

ADDITIONAL MONTHLY RATE

For Company-owned poles installed after October 5, 1964 required to be used for street lighting only.

Wood Pole ....$1.71 per pole
Steel Pole ....$6.80 per pole

UNDERGROUND CIRCUITS will be installed when the Customer pays the estimated cost difference between overhead and underground, or the Customer agrees to pay a monthly charge of 1.75 percent of the estimated cost difference.

"B" - ORNAMENTAL LIGHTING - CUSTOMER-OWNED SYSTEM

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed and owned by the Customer.

Service supplied by the Company includes operation of the system, energy, lamp renewals, cleaning of glassware, and replacement of defective ballasts and photocells which are standard to the Company owned street light units. Service does not include the labor or material cost of replacing cables, standards, broken glassware or fixtures, or painting or refinishing of metal poles.

SCHEDULE 41
STREET LIGHTING SERVICE

NO NEW SERVICE
(Continued)

MONTHLY CHARGE PER LAMP

Incandescent	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
	2,500	$ 2.82	$0.40	$ 3.22
Mercury Vapor				
175 Watt	7,654	$ 5.22	$0.42	$ 5.64
400 Watt	19,125	$ 8.23	$0.98	$ 9.21
1000 Watt	47,000	$14.02	$2.34	$16.36
High Pressure Sodium Vapor				
70 Watt	5,200	$ 3.02	$0.18	$ 3.20

*This Power Cost Adjustment is computed as provided in Schedule 55.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 42
TRAFFIC CONTROL SIGNAL
LIGHTING SERVICE

APPLICABILITY

Service under this schedule is applicable to Electric Service required for the operation of traffic control signal lights within the State of Idaho. Traffic control signal lamps are mounted on posts or standards by means of brackets, mast arms, or cable.

The traffic control signal fixtures, including posts or standards, brackets, mast arm, cable, lamps, control mechanisms, fixtures, service cable, and conduit to the point of, and with suitable terminals for, connection to the Company's underground or overhead distribution system, are installed, owned, maintained and operated by the Customer. Service is limited to the supply of energy only for the operation of traffic control signal lights.

MONTHLY CHARGES

The average monthly kWh of energy usage shall be estimated by the Company based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated; PROVIDED, HOWEVER, at the Company's option, the wattage of the signal may be determined by test.

Base Rate	Power Cost Adjustment*	Effective Rate*
3.105¢	0.604¢	3.709¢

*This Power Cost Adjustment is computed as provided in Schedule 55.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 55
POWER COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers served under the Company's schedules, to the primary portion of the FMC Special Contract, and to all other Idaho retail Special Contracts. These loads are referred to as "firm" load for purposes of this schedule.

BASE POWER COST

The Base Power Cost of the Company's rates is computed by dividing the Company's power cost components by firm kWh load. The power cost components are the sum of fuel expense and purchased power expense (including purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue and FMC secondary load revenue. The Base Power Cost is 0.5238 cents per kWh.

PROJECTED POWER COST

The Projected Power Cost is the Company estimate, expressed in cents per kWh, of the power cost components for the forecasted time period beginning April 1 each year and ending the following March 31. The Projected Power Cost is 0.7971 cents per kWh.

TRUE-UP

The True-up is based upon the difference between the previous Projected Power Cost and the power costs actually incurred. The True-up is 0.3579 cents per kWh.

POWER COST ADJUSTMENT

The Power Cost Adjustment is 90 percent of the difference between the Projected Power Cost and the Base Power Cost plus the True-up.

The monthly Power Cost Adjustment applied to the Energy rate for Irrigation Service (Schedules 24 and 25) is 1.3159 cents per kWh, for Small General Service (Schedule 7) is 0.8477 cents per kWh and Large Power Service (Schedule 19) is 0.8217 cents per kWh. The monthly Power Cost Adjustment applied to the Energy rate of all other metered schedules and Special Contracts is 0.6039 cents per kWh. The monthly Power Cost Adjustment applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times 0.6039 cents per kWh.

EXPIRATION

The Power Cost Adjustment included on this schedule will expire May 31, 2004.

SCHEDULE 1
RESIDENTIAL SERVICE
(Continued)

RESIDENTIAL SPACE HEATING

All space heating equipment to be served by the Company's system shall be single phase equipment approved by Underwriters' Laboratories, Inc., and the equipment and its installation shall conform to all National, State and Municipal Codes and to the following:

Individual resistance-type units for space heating larger than 1,650 watts shall be designed to operate at 240 or 208 volts, and no single unit shall be larger than 6 kW. Heating units of two kW or larger shall be controlled by approved thermostatic devices. When a group of heating units, with a total capacity of more than 6 kW, is to be actuated by a single thermostat, the controlling switch shall be so designed that not more than 6 kW can be switched on or off at any one time. Supplemental resistance-type heaters, that may be used with a heat exchanger, shall comply with the specifications listed above for such units.

MONTHLY CHARGE

The Monthly Charge is the sum of the Customer and the Energy Charges at the following rates:

Customer Charge
$2.51 per meter per month

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
4.9303¢	0.6039¢	5.5342¢

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge and the Energy Charge.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 7
SMALL GENERAL SERVICE
(Continued)

MONTHLY CHARGE (Continued)

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge and the Energy Charge.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

SECONDARY SERVICE (Continued)

Facilities Charge
None

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, and the Energy Charge.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PRIMARY SERVICE

Customer Charge
$85.58 per meter per month

Basic Charge
$0.77 per kW of Basic Load Capacity

Demand Charge
$2.65 per kW for all kW of Demand

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.1308¢	0.6039¢	2.7347¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

EXHIBIT NO. 1
CASE NO. IPC-E-04-__
G. SAID, IPCO

SCHEDULE 9
LARGE GENERAL SERVICE
(Continued)

TRANSMISSION SERVICE

Customer Charge
$85.58 per meter per month

Basic Charge
$0.39 per kW of Basic Load Capacity

Demand Charge
$2.57 per kW for all kW of Demand

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.0833¢	0.6039¢	2.6872¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 15
DUSK TO DAWN CUSTOMER LIGHTING
(Continued)

MONTHLY CHARGES (Continued)

FLOOD LIGHTING

High Pressure Sodium Vapor	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
200 Watt	19,800	$17.18	$0.41	$17.59
400 Watt	45,000	$25.63	$0.83	$26.46
Metal Halide				
400 Watt	28,800	$28.64	$0.83	$29.47
1000 Watt	88,000	$52.28	$2.07	$54.35

* This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

2. The Monthly Charge for New Facilities to be installed, such as overhead (or equivalent) secondary conductor, poles, anchors, etc., shall be 1.75 percent of the estimated installed cost thereof.

3. The Company may provide underground service from existing secondary facilities when the Customer pays the estimated nonsalvable cost of underground facilities.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

SECONDARY SERVICE (Continued)

Facilities Charge
None

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, and the Energy Charge.

*This Power Cost Adjustment is computed as provided in (Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PRIMARY SERVICE

Customer Charge
$85.71 per meter per month

Basic Charge
$0.77 per kW of Basic Load Capacity

Demand Charge
$2.65 per kW for all kW of Billing Demand

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.0839¢	0.8217¢	2.9056¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in (Schedule 55~~), and Effective Rate expire May 15, 2004~~.

SCHEDULE 19
LARGE POWER SERVICE
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE

Customer Charge
$85.71 per meter per month

Basic Charge
$0.39 per kW of Basic Load Capacity

Demand Charge
$2.57 per kW for all kW of Billing Demand

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.0375¢	0.8217¢	2.8592¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Basic Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in (Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PAYMENT

The monthly bill for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 24
IRRIGATION SERVICE
(Continued)

FACILITIES BEYOND THE POINT OF DELIVERY (Continued)

In the event the Customer requests the Company to remove or reinstall or change Company-owned Facilities Beyond the Point of Delivery, the Customer shall pay to the Company the "non-salvable cost" of such removal, reinstallation or change. Non-salvable cost as used herein is comprised of the total original costs of materials, labor and overheads of the facilities, less the difference between the salvable cost of material removed and removal labor cost including appropriate overhead costs.

POWER FACTOR ADJUSTMENT

Where the Customer's Power Factor is less than 85 percent, as determined by measurement under actual load conditions, the Company may adjust the kW measured to determine the Billing Demand by multiplying the measured kW by 85 percent and dividing by the actual Power Factor.

MONTHLY CHARGE

The Monthly Charge is the sum of the Customer, the Demand, the Energy, and the Facilities Charges at the following rates.

SECONDARY SERVICE

Customer Charge

$10.07 per meter per month	Irrigation Season
$ 2.50 per meter per month	Out of Season

Demand Charge

$3.58 per kW of Billing Demand	Irrigation Season
No Demand Charge	Out of Season

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.8416¢	1.3159¢	4.1575¢ per kWh for all kWh Irrigation Season
3.6172¢	1.3159¢	4.9331¢ per kWh for all kWh Out of Season

Facilities Charge
None

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Demand Charge, and the Energy Charge.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

SCHEDULE 24
IRRIGATION SERVICE
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE

Customer Charge
$85.61 per meter per month Irrigation Season
$ 2.50 per meter per month Out of Season

Demand Charge
$3.37 per kW of Billing Demand Irrigation Season
No Demand Charge Out of Season

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
2.7021¢	1.3159¢	4.0180¢ per kWh for all kWh Irrigation Season
3.4396¢	1.3159¢	4.7555¢ per kWh for all kWh Out of Season

Facilities Charge

The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PAYMENT

All monthly billings for Electric Service supplied hereunder are payable upon receipt, and become past due 15 days from the date on which rendered. (For any agency or taxing district which has notified the Company in writing that it falls within the provisions of Idaho Code § 67–2302, the past due date will reflect the 60 day payment period provided by Idaho Code § 67–2302.)

Deposit. A deposit payment for irrigation Customers is required under the following conditions:

1. Existing Customers: Customers who have two or more reminder notices for nonpayment of Electric Service during a 12-month period or who have service disconnected for non-payment will be required to pay a deposit, or provide a guarantee of payment from a bank or financial institution acceptable to the Company. A reminder notice is issued approximately 45 days after the bill issue date if the balance owing for Electric Service totals $100 or more or approximately 105 days after the bill issue date for Customers meeting the provisions of Idaho Code § 67–2302. The deposit for a specific installation will be computed as follows:

SCHEDULE 25
IRRIGATION SERVICE – TIME-OF-USE
PILOT PROGRAM
(OPTIONAL)
(Continued)

MONTHLY CHARGE

The Monthly Charge is the sum of the Customer, the TOU Metering, the Demand, the Energy, and the Facilities Charges at the following rates.

SECONDARY SERVICE

Customer Charge

$10.07 per meter per month	Irrigation Season
$ 2.50 per meter per month	Out of Season

TOU Metering Charge

$3.00 per meter per month	Irrigation Season
No TOU Meter Charge	Out of Season

Demand Charge

$3.58 per kW of Billing Demand	Irrigation Season
No Demand Charge	Out of Season

Energy Charge

	Base Rate	Power Cost Adjustment*	Effective Rate*
	IN-SEASON		
On-Peak	4.9728¢	1.3159¢	6.2887¢ per kWh for all kWh
Mid-Peak	2.8416¢	1.3159¢	4.1575¢ per kWh for all kWh
Off-Peak	1.4208¢	1.3159¢	2.7367¢ per kWh for all kWh
	OUT-OF-SEASON		
	3.6172¢	1.3159¢	4.9331¢ per kWh for all kWh

Facilities Charge
None

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the TOU Metering Charge, the Demand Charge, and the Energy Charge.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

EXHIBIT NO. 1
CASE NO. IPC-E-04-__
G. SAID, IPCO
Page 32 of 44

SCHEDULE 25
IRRIGATION SERVICE – TIME-OF-USE
PILOT PROGRAM
(OPTIONAL)
(Continued)

MONTHLY CHARGE (Continued)

TRANSMISSION SERVICE

Customer Charge
$85.61 per meter per month — Irrigation Season
$ 2.50 per meter per month — Out of Season

TOU Metering Charge
None

Demand Charge
$3.37 per kW of Billing Demand — Irrigation Season
No Demand Charge — Out of Season

Energy Charge

	Base Rate	Power Cost Adjustment*	Effective Rate*
	IN-SEASON		
On-Peak	4.7287¢	1.3159¢	6.0446¢ per kWh for all kWh
Mid-Peak	2.7021¢	1.3159¢	4.0180¢ per kWh for all kWh
Off-Peak	1.3511¢	1.3159¢	2.6670¢ per kWh for all kWh
	OUT-OF-SEASON		
	3.4396¢	1.3159¢	4.7555¢ per kWh for all kWh

Facilities Charge
The Company's investment in Company-owned Facilities Beyond the Point of Delivery times 1.7 percent.

Minimum Charge
The monthly Minimum Charge shall be the sum of the Customer Charge, the Demand Charge, the Energy Charge, and the Facilities Charge.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
SCHEDULE 26
FOR
MICRON TECHNOLOGY, INC.
BOISE, IDAHO

SPECIAL CONTRACT DATED SEPTEMBER 1, 1995
(Continued)

MONTHLY ENERGY CHARGE

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
12.783	6.039	18.822 mills per kWh for all energy

*This Power Cost Adjustment is computed as provided in (Schedule 55~~), and Effective Rate expire May 15, 2004~~.

MONTHLY O & M CHARGES

0.4 percent of total cost of Substation Facilities.

CONSERVATION PROGRAMS RECOVERY CHARGE

$5,703 per month

IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
SCHEDULE 29
J. R. SIMPLOT COMPANY
POCATELLO, IDAHO

SPECIAL CONTRACT DATED AUGUST 27, 1973

MONTHLY CONTRACT RATE

Demand Charge
$6.68 per kW of Billing Demand (1)

Energy Charge

Base Rate	Power Cost Adjustment*	Effective Rate*
14.080	6.039	20.119 mills per kWh for all energy (2)

Minimum Charge

The minimum monthly charge shall be the amount computed in accordance with Paragraph 5.1, but not less $100,188.61 for any month during the effective term of this Agreement.

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

CONSERVATION PROGRAMS RECOVERY CHARGE

$5,061 per month

Contract Changes

(1) Contract Paragraph No 5.1(a).

No Change

(2) Contract Paragraph No. 5.1(b)
Change 33.450 mills to 20.119 mills

(3) Contract Paragraph No. 5.2.

No Change

IDAHO POWER COMPANY
ELECTRIC SERVICE RATE
SCHEDULE 30
FOR
UNITED STATES DEPARTMENT OF ENERGY
IDAHO OPERATIONS OFFICE

SPECIAL CONTRACT DATED MAY 16, 2000
CONTRACT NO. GS-OOP-99-BSD-0124

AVAILABILITY

This schedule is available for firm retail service of electric power and energy delivered for the operations of the Department of Energy's facilities located at the Idaho National Engineering Laboratory site, as provided in the Contract for Electric Service between the parties.

MONTHLY CHARGE

The monthly charge for electric service shall be the sum of the Demand, Energy, and Conservation Programs Recovery Charges determined at the following rates:

1. Demand Charge:

   $5.10 per kW of Billing Demand Per Month

2. Energy Charge:

Base Rate	Power Cost Adjustment*	Effective Rate*
13.404	6.039	19.443 mills per kWh for all energy

3. Conservation Programs Recovery Charge

   $3,521 per month

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

SPECIAL CONDITIONS

1. Billing Demand:

The Billing Demand shall be the average kW supplied during the 30-minute period of maximum use during the month.

2. Power Factor Adjustment:

When the Power Factor is less than 95 percent during the 30-minute period of maximum load for the month, Company may adjust the measured Demand to determine the Billing Demand by multiplying the measured kW of Demand by 0.95 and dividing by the actual Power Factor.

IDAHO POWER COMPANY
AGREEMENT FOR SUPPLY OF SHIELDED
STREET LIGHTING SERVICE
SCHEDULE 32
FOR THE CITY OF KETCHUM, IDAHO

SPECIAL CONTRACT DATED JUNE 12, 2001

MONTHLY CHARGE PER LAMP

High Pressure Sodium Vapor	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
70 Watt	6,400	$ 7.07	$0.14	$ 7.21
100 Watt	9,500	$ 7.64	$0.21	$ 7.85
200 Watt	22,000	$ 9.59	$0.41	$10.00

*This Power Cost Adjustment is computed as provided in (Schedule 55~~) and this Effective Rate expire May 15, 2004~~.

ADDITIONAL MONTHLY RATE

For Company-owned poles installed after October 5, 1964 required to be used for street lighting only:

Wood pole ....$1.71 per pole
Steel pole ....$6.80 per pole

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 40
UNMETERED GENERAL SERVICE

AVAILABILITY

Service under this schedule is available at points on the Company's interconnected system within the State of Idaho where existing secondary distribution facilities of adequate capacity, phase and voltage are available adjacent to the Customer's Premises and the only investment required by the Company is an overhead service drop.

APPLICABILITY

Service under this schedule applies to Electric Service for the Customer's single- or multiple-unit loads up to 1,800 watts per unit where the size of the load and period of operation are fixed and, as a result, actual usage can be accurately determined. Service may include, but is not limited to, street and highway lighting, security lighting, telephone booths and CATV power supplies which serve line amplifiers. Facilities to supply service under this schedule shall be installed so that service cannot be extended to the Customer's loads served under other schedules. Service under this schedule is not applicable to shared or temporary service, or to the Customer's loads on Premises which have metered service.

SPECIAL TERMS AND CONDITIONS

The Customer shall pay for all Company investment, except the overhead service drop, required to provide service requested by the Customer. The Customer is responsible for installing, owning and maintaining all equipment, including necessary underground circuitry and related facilities to connect with the Company's facilities at the Company designated Point of Delivery. If the Customer's equipment is not properly maintained, service to the specific equipment will be terminated.

Energy used by CATV power supplies which serve line amplifiers will be determined by the power supply manufacturer's nameplate input rating assuming continuous operation.

The Company is only responsible for supplying energy to the Point of Delivery and, at its expense, may check energy consumption at any time.

MONTHLY CHARGE

The average monthly kWh of energy usage shall be estimated by the Company, based on the Customer's electric equipment and one-twelfth of the annual hours of operation thereof. Since the service provided is unmetered, failure of the Customer's equipment will not be reason for a reduction in the Monthly Charge. The Monthly Charge shall be computed at the following rate:

Base Rate	Power Cost Adjustment*	Effective Rate*
5.68¢	0.604¢	6.284¢ per kWh for all kWh

Minimum Charge
$1.50 per month

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

EXHIBIT NO. 1
CASE NO. IPC-E-04-__
G. SAID, IPCO
Page 38 of 44

SCHEDULE 41
STREET LIGHTING SERVICE

AVAILABILITY

Service under this schedule is available throughout the Company's service area within the State of Idaho where street lighting wires and fixtures can be installed on the Company's existing distribution facilities.

APPLICABILITY

Service under this schedule is applicable to service required by municipalities or agencies of federal, state, or county governments for the lighting of public streets, alleys, public grounds, and thoroughfares. Street lighting lamps will be energized each night from dusk until dawn.

SERVICE LOCATION AND PERIOD

Street lighting facility locations, type of unit and lamp sizes, as changed from time to time by written request of the Customer and agreed to by the Company, shall be as shown on an Exhibit A for each Customer receiving service under this schedule. The in-service date for each street lighting facility will be maintained on the Exhibit A.

The minimum service period for any street lighting facility is 10 years. The Company, upon written notification from the Customer, will remove a street lighting facility:

1. At no cost to the Customer, if such facility has been in service for no less than the minimum service period;

2. Upon payment to the Company of the removal cost, if such facility has been in service for less than the minimum service period.

"A" - OVERHEAD LIGHTING - COMPANY-OWNED SYSTEM

The facilities required for supplying service, including fixture, lamp, control relay, mast arm or mounting on an existing utility pole, and energy for the operation thereof, are supplied, installed, owned and maintained by the Company. All necessary repairs, maintenance work, including group lamp replacement and glassware cleaning, will be performed by the Company during the regularly scheduled working hours of the Company on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements.

MONTHLY CHARGE PER LAMP

High Pressure Sodium Vapor	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
100 Watt	8,550	$ 6.37	$0.25	$ 6.62
200 Watt	19,800	$ 7.44	$0.48	$ 7.92
400 Watt	45,000	$10.60	$1.00	$11.60

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

EXHIBIT NO. 1
CASE NO. IPC-E-04-__
G. SAID, IPCO

SCHEDULE 41
STREET LIGHTING SERVICE
(Continued)

ADDITIONAL MONTHLY RATE

For Company-owned poles installed after October 5, 1964 required to be used for street lighting only:

Wood pole...$1.71 per pole
Steel pole..$6.80 per pole

UNDERGROUND CIRCUITS will be installed when the Customer pays the estimated cost difference between overhead and underground, or the Customer agrees to pay a monthly charge of 1.75 percent of the estimated cost difference.

"B" - CUSTOMER-OWNED SYSTEM

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed and owned by the Customer.

Service supplied by the Company includes operation of the system, energy, lamp renewals, cleaning of glassware, and replacement of defective ballasts and photocells which are standard to the Company-owned street light units. Service does not include the labor or material cost of replacing cables, standards, broken glassware or fixtures, or painting or refinishing of metal poles.

MONTHLY CHARGE PER LAMP

High Pressure Sodium Vapor	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
100 Watt	8,550	$3.45	$0.25	$ 3.70
200 Watt	19,800	$4.75	$0.48	$ 5.23
250 Watt	24,750	$5.69	$0.63	$ 6.32
400 Watt	45,000	$7.87	$1.00	$ 8.87

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 41
STREET LIGHTING SERVICE

NO NEW SERVICE
(Continued)

MONTHLY CHARGE PER LAMP

	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
Mercury Vapor				
175 Watt	7,700	$ 6.99	$0.42	$ 7.41
400 Watt	18,800	$11.59	$0.98	$12.57
High Pressure Sodium Vapor				
150 Watt	13,800	$ 6.89	$0.36	$ 7.25
250 Watt	24,750	$ 8.42	$0.63	$ 9.05

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

ADDITIONAL MONTHLY RATE

For Company-owned poles installed after October 5, 1964 required to be used for street lighting only.

Wood Pole ....$1.71 per pole
Steel Pole ....$6.80 per pole

UNDERGROUND CIRCUITS will be installed when the Customer pays the estimated cost difference between overhead and underground, or the Customer agrees to pay a monthly charge of 1.75 percent of the estimated cost difference.

"B" - ORNAMENTAL LIGHTING - CUSTOMER-OWNED SYSTEM

The Customer's lighting system, including posts or standards, fixtures, initial installation of lamps and underground cables with suitable terminals for connection to the Company's distribution system, is installed and owned by the Customer.

Service supplied by the Company includes operation of the system, energy, lamp renewals, cleaning of glassware, and replacement of defective ballasts and photocells which are standard to the Company owned street light units. Service does not include the labor or material cost of replacing cables, standards, broken glassware or fixtures, or painting or refinishing of metal poles.

SCHEDULE 41
STREET LIGHTING SERVICE

NO NEW SERVICE
(Continued)

MONTHLY CHARGE PER LAMP

Incandescent	Average Lumens	Base Rate	Power Cost Adjustment*	Effective Rate*
	2,500	$ 2.82	$0.40	$ 3.22
Mercury Vapor				
175 Watt	7,654	$ 5.22	$0.42	$ 5.64
400 Watt	19,125	$ 8.23	$0.98	$ 9.21
1000 Watt	47,000	$14.02	$2.34	$16.36
High Pressure Sodium Vapor				
70 Watt	5,200	$ 3.02	$0.18	$ 3.20

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 42
TRAFFIC CONTROL SIGNAL
LIGHTING SERVICE

APPLICABILITY

Service under this schedule is applicable to Electric Service required for the operation of traffic control signal lights within the State of Idaho. Traffic control signal lamps are mounted on posts or standards by means of brackets, mast arms, or cable.

The traffic control signal fixtures, including posts or standards, brackets, mast arm, cable, lamps, control mechanisms, fixtures, service cable, and conduit to the point of, and with suitable terminals for, connection to the Company's underground or overhead distribution system, are installed, owned, maintained and operated by the Customer. Service is limited to the supply of energy only for the operation of traffic control signal lights.

MONTHLY CHARGES

The average monthly kWh of energy usage shall be estimated by the Company based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated; PROVIDED, HOWEVER, at the Company's option, the wattage of the signal may be determined by test.

Base Rate	Power Cost Adjustment*	Effective Rate*
3.105¢	0.604¢	3.709¢

*This Power Cost Adjustment is computed as provided in ~~(~~Schedule 55~~), and Effective Rate expire May 15, 2004~~.

PAYMENT

The monthly bill rendered for service supplied hereunder is payable upon receipt, and becomes past due 15 days from the date on which rendered.

SCHEDULE 55
POWER COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers served under the Company's schedules, to the primary portion of the FMC Special Contract, and to all other Idaho retail Special Contracts. These loads are referred to as "firm" load for purposes of this schedule.

BASE POWER COST

The Base Power Cost of the Company's rates is computed by dividing the Company's power cost components by firm kWh load. The power cost components are the sum of fuel expense and purchased power expense (including purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue and FMC secondary load revenue. The Base Power Cost is 0.5238 cents per kWh.

PROJECTED POWER COST

The Projected Power Cost is the Company estimate, expressed in cents per kWh, of the power cost components for the forecasted time period beginning April 1 each year and ending the following March 31. The Projected Power Cost is 0.7971 cents per kWh.

TRUE-UP

The True-up is based upon the difference between the previous Projected Power Cost and the power costs actually incurred. The True-up is 0.3579 cents per kWh.

POWER COST ADJUSTMENT

The Power Cost Adjustment is 90 percent of the difference between the Projected Power Cost and the Base Power Cost plus the True-up.

The monthly Power Cost Adjustment applied to the Energy rate for Irrigation Service (Schedules 24 and 25) is 1.3159 cents per kWh, for Small General Service (Schedule 7) is 0.8477 cents per kWh and Large Power Service (Schedule 19) is 0.8217 cents per kWh. The monthly Power Cost Adjustment applied to the Energy rate of all other metered schedules and Special Contracts is 0.6039 cents per kWh. The monthly Power Cost Adjustment applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times 0.6039 cents per kWh.

EXPIRATION

The Power Cost Adjustment included on this schedule will expire May ~~15~~31, 2004.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-09

IDAHO POWER COMPANY

EXHIBIT NO. 2

G. SAID

PCA Regression Derivation

obs.	year	runoff	ln(runoff)		npsc		predicted y
1	1928	6,966,928	15.76	$	24,896,784	$	33,177,543
2	1929	3,689,911	15.12	$	50,873,982	$	71,886,172
3	1930	2,911,496	14.88	$	98,727,170	$	81,080,931
4	1931	2,381,175	14.68	$	106,958,582	$	87,345,159
5	1932	4,861,787	15.40	$	73,646,054	$	58,043,790
6	1933	4,250,553	15.26	$	81,740,688	$	65,263,784
7	1934	2,381,897	14.68	$	131,019,720	$	87,336,631
8	1935	3,172,748	14.97	$	103,166,102	$	77,994,972
9	1936	5,136,066	15.45	$	68,134,235	$	54,803,973
10	1937	3,195,479	14.98	$	67,351,698	$	77,726,475
11	1938	7,167,188	15.79	$	12,664,916	$	30,812,051
12	1939	3,522,159	15.07	$	69,189,270	$	73,867,685
13	1940	4,342,590	15.28	$	60,822,409	$	64,176,628
14	1941	3,999,227	15.20	$	64,683,087	$	68,232,480
15	1942	4,977,822	15.42	$	33,478,159	$	56,673,167
16	1943	9,546,645	16.07	$	20,156,051	$	2,705,541
17	1944	3,579,035	15.09	$	57,457,371	$	73,195,857
18	1945	5,309,857	15.49	$	11,349,386	$	52,751,118
19	1946	7,055,496	15.77	$	25,634,128	$	32,131,365
20	1947	5,348,955	15.49	$	35,644,106	$	52,289,285
21	1948	5,895,433	15.59	$	23,192,016	$	45,834,203
22	1949	5,448,833	15.51	$	36,487,169	$	51,109,514
23	1950	6,849,217	15.74	$	16,413,270	$	34,567,964
24	1951	7,103,576	15.78	$	20,141,713	$	31,563,444
25	1952	10,862,977	16.20	$	22,402,752	$	(12,843,179)
26	1953	6,407,278	15.67	$	29,088,318	$	39,788,217
27	1954	5,554,042	15.53	$	56,282,988	$	49,866,767
28	1955	3,866,501	15.17	$	36,288,665	$	69,800,259
29	1956	7,902,304	15.88	$	19,602,283	$	22,128,749
30	1957	8,295,186	15.93	$	16,827,186	$	17,487,967
31	1958	7,496,672	15.83	$	37,839,082	$	26,920,132
32	1959	4,184,210	15.25	$	54,882,387	$	66,047,439
33	1960	4,357,605	15.29	$	74,891,892	$	63,999,270
34	1961	3,096,603	14.95	$	93,255,958	$	78,894,414
35	1962	5,076,278	15.44	$	39,952,360	$	55,510,195
36	1963	5,052,040	15.44	$	44,538,500	$	55,796,498
37	1964	6,384,427	15.67	$	11,281,426	$	40,058,143
38	1965	9,015,991	16.01	$	14,242,774	$	8,973,705
39	1966	3,273,937	15.00	$	83,086,380	$	76,799,715
40	1967	5,483,615	15.52	$	21,541,691	$	50,698,662
41	1968	3,361,950	15.03	$	33,490,176	$	75,760,097
42	1969	7,078,054	15.77	$	33,503,094	$	31,864,906
43	1970	6,586,665	15.70	$	7,748,587	$	37,669,269
44	1971	11,260,594	16.24	$	5,867,224	$	(17,539,886)
45	1972	8,267,498	15.93	$	16,384,317	$	17,815,013
46	1973	4,010,676	15.20	$	16,141,798	$	68,097,248
47	1974	9,976,606	16.12	$	24,672,812	$	(2,373,224)
48	1975	9,101,832	16.02	$	5,910,962	$	7,959,742
49	1976	7,948,088	15.89	$	34,409,346	$	21,587,936
50	1977	2,161,615	14.59	$	99,856,791	$	89,938,639
51	1978	6,050,594	15.62	$	8,291,623	$	44,001,418
52	1979	3,840,423	15.16	$	63,731,656	$	70,108,305
53	1980	6,377,115	15.67	$	17,816,446	$	40,144,502
54	1981	4,055,248	15.22	$	55,844,377	$	67,570,750
55	1982	9,782,115	16.10	$	7,972,516	$	(75,864)
56	1983	10,702,685	16.19	$	(5,749,822)	$	(10,949,783)
57	1984	12,630,563	16.35	$	(8,366,250)	$	(33,722,175)
58	1985	5,636,055	15.54	$	29,873,368	$	48,898,022
59	1986	8,819,397	15.99	$	1,589,769	$	11,295,900
60	1987	2,826,920	14.85	$	95,802,567	$	82,079,946
61	1988	2,629,206	14.78	$	97,566,626	$	84,415,378
62	1989	4,617,913	15.35	$	64,156,115	$	60,924,464
63	1990	3,015,713	14.92	$	111,640,117	$	79,849,898
64	1991	2,771,215	14.83	$	115,906,144	$	82,737,951
65	1992	1,967,302	14.49	$	132,400,389	$	92,233,891
66	1993	6,085,398	15.62	$	31,494,407	$	43,590,308
67	1994	2,615,546	14.78	$	97,009,455	$	84,576,734
68	1995	6,779,568	15.73	$	25,980,878	$	35,390,675
69	1996	8,398,725	15.94	$	25,197,262	$	16,264,946
70	1997	9,908,172	16.11	$	17,915,497	$	(1,564,874)
71	1998	8,951,599	16.01	$	9,859,071	$	9,734,306
72	1999	7,985,776	15.89	$	20,443,802	$	21,142,760
73	2000	4,370,706	15.29	$	79,021,382	$	63,844,521
74	2001	2,392,435	14.69	$	120,608,324	$	87,212,152
75	2002	3,246,067	14.99	$	118,285,937	$	77,128,917
averages		5,754,850	15.46	$	47,494,793	$	47,494,793

regression statistics	
multiple r	0.8861
r square	0.7852
adjusted r square	0.7823
standard error	17,148,522
observations	75
anova	
	df
regression	1
residual	73
total	74
coefficients	
intercept	1,140,615,325
x variable 1	(70,685,112)

EXHIBIT NO. 2
CASE NO. IPC-E-04-__
G.SAID, IPCO

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-09

IDAHO POWER COMPANY

EXHIBIT NO. 3

G. SAID

National Weather Service
Water Supply Forecast

Water Supply Forecasts
Northwest River Forecast Center
Wednesday April 07, 2004 at 21:36 GMT

Full month of observed precipitation
75% prec thru mid April then
Future precip applied at 100% of normal
Snow included in this run
Full complement runoff applied

UPPER COLUMBIA BASINS

Apr-04FINAL — W A T E R S U P P L Y F O R E C A S T S

STREAM AND STATION	PERIOD	FORECAST PROBABLE	%	MAXIMUM	%	RUNOFF MINIMUM	%	AVERAGE RUNOFF	RO PREV YR PERIOD	CURR RO TO DATE	WY
COLUMBIA RIVER											
MICA RESERVOIR INFLOW, BC	JAN-JUL	9170.0	95	10500.0	109	7850.0	82	9619.	9079	2677	131
	FEB-SEP	12300.0	95	13700.0	106	11000.0	85	12960.	11800	2677	131
	APR-SEP	11900.0	95	13200.0	106	10600.0	85	12500.	11360	2677	131
REVELSTOKE, BC	JAN-JUL	13400.0	97	14600.0	105	12300.0	89	13880.	12860	3763	128
ARROW LAKES INFLOW	JAN-JUL	19700.0	94	21800.0	104	17700.0	84	20960.	18580	5759	109
	FEB-SEP	25000.0	94	27100.0	102	22900.0	87	26460.	22700	5759	109
	APR-SEP	23900.0	95	25900.0	103	21800.0	87	25110.	21650	5759	109
BIRCHBANK, BC (1)	JAN-JUL	35200.0	90	40500.0	104	30000.0	77	38930.	34250	10140	109
	APR-SEP	39600.0	91	44800.0	103	34300.0	79	43500.	37220	10140	109
GRAND COULEE, WA (1)	JAN-JUL	53600.0	85	62100.0	99	45000.0	72	62900.	54180	15170	87
	APR-SEP	55500.0	87	64000.0	100	46900.0	73	63990.	52740	15170	87
ROCK ISLAND DAM BLO, WA (1)	JAN-JUL	58900.0	85	68300.0	99	49500.0	72	68910.	58540	16810	89
	APR-SEP	60300.0	87	69700.0	100	50900.0	73	69540.	56310	16810	89
THE DALLES NR, OR (1)	JAN-JUL	84200.0	78	97800.0	91	70600.0	66	107300.	87690	32280	82
	APR-AUG	73400.0	79	87000.0	93	59900.0	64	93090.	73770	32280	82
	APR-SEP	77800.0	79	91400.0	93	64200.0	65	98650.	77440	32280	82
KOOTENAI RIVER											
LIBBY RES INFLOW, MT (1)	JAN-JUL	5290.0	84	6590.0	105	3990.0	63	6306.	5187	1351	87
	APR-AUG	5300.0	85	6600.0	106	4000.0	64	6248.	5084	1351	87
	APR-SEP	5630.0	85	6930.0	104	4330.0	65	6638.	5340	1351	87
LIBBY, MT (1)	JAN-SEP	6530.0	82	7990.0	101	5070.0	64	7936.	6154	1476	89
	APR-SEP	5940.0	82	7400.0	103	4480.0	62	7207.	5582	1476	89
LEONIA, ID (1)	APR-JUL	5830.0	83	7410.0	105	4250.0	60	7041.	5608	1721	80
	APR-SEP	6730.0	83	8310.0	102	5150.0	63	8125.	6276	1721	80
BONNERS FERRY, ID	APR-JUL	6360.0	83	7900.0	104	4810.0	63	7619.	5943	1827	78
KOOTENAY RIVER											
KOOTENAY LAKE INFLOW, BC	JAN-JUL	13500.0	84	15700.0	98	11200.0	70	16010.	13420	3604	92
	APR-SEP	14000.0	85	16600.0	101	11400.0	69	16450.	13430	3604	92
DUNCAN RIVER											
DUNCAN RESERVOIR INFLOW, BC	JAN-JUL	1740.0	97	2110.0	117	1360.0	76	1800.	1696	540	143
	FEB-SEP	2250.0	98	2630.0	114	1880.0	82	2305.	2147	540	143
	APR-SEP	2180.0	98	2550.0	115	1800.0	81	2227.	2066	540	143
CLARK FORK											
BLACKFOOT RIVER ABV, MT	APR-SEP	485.0	69	815.0	116	154.0	22	704.	617	268	78
MISSOULA ABV, MT	APR-SEP	1120.0	70	1580.0	99	660.0	41	1595.	1353	475	81
MISSOULA BLO, MT	APR-SEP	2070.0	70	2770.0	94	1380.0	47	2962.	2767	766	79
ST. REGIS, MT (1)	APR-SEP	2780.0	71	3850.0	99	1710.0	44	3907.	3591	1004	76
PLAINS NR, MT (1)	APR-SEP	8190.0	74	10500.0	95	5910.0	53	11060.	8624	1998	64
WHITEHORSE RAPIDS, ID (1)	APR-SEP	9290.0	75	11900.0	96	6640.0	53	12460.	9321	2324	62
BLACKFOOT RIVER											
BONNER NR, MT	APR-SEP	635.0	71	920.0	103	345.0	39	892.	736	208	87
BITTERROOT RIVER											
AT MOUTH, MT	APR-SEP	955.0	70	1240.0	91	670.0	49	1364.	1317	261	67

Apr-04FINAL — W A T E R S U P P L Y F O R E C A S T S

STREAM AND STATION	PERIOD	FORECAST PROBABLE	%	MAXIMUM	%	RUNOFF MINIMUM	%	AVERAGE RUNOFF	RO PREV YR PERIOD	CURR RO TO DATE	WY
N.F. FLATHEAD RIVE											
COLUMBIA FALLS NR, MT	APR-SEP	1400.0	78	1750.0	97	1050.0	58	1801.	1404	301	83
M.F. FLATHEAD RIVE											
WEST GLACIER NR, MT	APR-SEP	1340.0	77	1620.0	93	1050.0	60	1740.	1418	234	67
S.F. FLATHEAD RIVE											
HUNGRY HORSE RES IN, MT (1)	JAN-JUL	1680.0	76	2130.0	96	1240.0	56	2224.	1817	364	79
	APR-SEP	1580.0	74	2020.0	95	1140.0	54	2124.	1692	364	79

Exhibit No. 3
Case No. IPC-E-04-__
G. Said, IPCO

UPPER/MIDDLE COLUMBIA BASINS

Apr-04FINAL   W A T E R   S U P P L Y   F O R E C A S T S

STREAM AND STATION DATE	PERIOD	FORECAST PROBABLE	%	MAXIMUM	%	RUNOFF MINIMUM	%	AVERAGE RUNOFF	RO PREV YR PERIOD	CURR RO TO	WY
FLATHEAD RIVER											
COLUMBIA FALLS, MT	APR-SEP	4420.0	76	5690.0	98	3150.0	54	5825.	4553	919	75
FLATHEAD LAKE INFLOW, MT (1)	APR-SEP	5100.0	76	6480.0	97	3720.0	55	6713.	4984	1104	71
PRIEST RIVER											
PRIEST RIVER, ID (1)	APR-JUL	645.0	79	865.0	106	425.0	52	814.	662	238	66
PEND OREILLE RIVER											
PEND OREILLE LAKE IN, ID (1)	APR-SEP	10100.0	73	13000.0	93	7220.0	52	13910.	10350	3266	71
	APR-JUL	9250.0	73	12200.0	96	6350.0	50	12740.	9715	3266	71
BOX CANYON BLO, WA (1)	APR-SEP	10400.0	74	13400.0	95	7460.0	53	14090.	10850	3271	68
KETTLE RIVER											
LAURIER NR, WA	APR-SEP	1640.0	83	2000.0	101	1270.0	64	1972.	1569	157	57
COEUR D'ALENE RIVE											
ENAVILLE, ID (1)	APR-SEP	615.0	79	810.0	104	420.0	54	778.	419	428	73
	APR-JUL	585.0	79	780.0	106	390.0	53	739.	393	428	73
COEUR D'ALENE LAKE IN, ID	APR-JUL	1940.0	76	2580.0	101	1310.0	51	2552.	1367	1176	61
SPOKANE RIVER											
SPOKANE, WA (1)	APR-SEP	2180.0	79	2260.0	82	2100.0	77	2744.	1623	1310	66
ST JOE RIVER											
CALDER, ID	APR-SEP	950.0	79	1180.0	98	720.0	60	1205.	867	320	62
	APR-JUL	895.0	79	1120.0	99	660.0	58	1136.	814	320	62
OKANAGAN RIVER											
TONASKET NR, WA (1)	APR-SEP	1210.0	69	1770.0	100	650.0	37	1766.	847	444	91
SIMILKAMEEN RIVER											
NIGHTHAWK NR, WA (1)	APR-JUL	970.0	72	1330.0	99	605.0	45	1350.	807	346	128
	APR-SEP	1040.0	72	1410.0	97	680.0	47	1450.	837	346	128
METHOW RIVER											
PATEROS NR, WA (1)	APR-SEP	715.0	73	960.0	97	470.0	48	985.	674	255	143
CHELAN RIVER											
LAKE CHELAN INFLOW, WA (1)	APR-SEP	885.0	75	1060.0	89	710.0	60	1185.	973	484	147
WENATCHEE RIVER											
PESHASTIN, WA	APR-SEP	1230.0	75	1760.0	108	705.0	43	1635.	1263	698	110

YAKIMA AND MAINSTEM SNAKE BASINS

Apr-04FINAL   W A T E R   S U P P L Y   F O R E C A S T S

STREAM AND STATION DATE	PERIOD	FORECAST PROBABLE	%	MAXIMUM	%	RUNOFF MINIMUM	%	AVERAGE RUNOFF	RO PREV YR PERIOD	CURR RO TO	WY
YAKIMA RIVER											
KEECHELUS LAKE IN, WA (1)	APR-SEP	105.0	79	131.0	98	78.0	59	133.	97	108	90
CLE ELUM, WA	APR-SEP	710.0	79	810.0	90	605.0	67	903.	667	596	94
PARKER NR, WA	APR-SEP	1540.0	80	1760.0	92	1320.0	69	1918.	1554	1184	79
KACHESS RIVER											
KACHESS LAKE INFLOW, WA (1)	APR-SEP	95.0	79	115.0	96	76.0	63	120.	87	97	95
CLE ELUM RIVER											
CLE ELUM LAKE INFLOW, WA (1)	APR-SEP	350.0	78	405.0	90	295.0	66	448.	353	247	104
NACHES RIVER											
NACHES NR, WA	APR-SEP	695.0	83	790.0	94	600.0	72	837.	714	330	70
BUMPING RIVER											
BUMPING LAKE INFLOW, WA (1)	APR-SEP	112.0	84	130.0	97	95.0	71	134.	100	58	76
TIETON RIVER											
RIMROCK LAKE INFLOW, WA (1)	APR-SEP	205.0	85	235.0	97	173.0	71	242.	198	98	68
AHTANUM CREEKS											
TAMPICO NR, WA	APR-SEP	39.0	85	56.0	122	22.0	48	46.	0		
SNAKE RIVER											
JACKSON LAKE INFLOW, WY (1)	APR-SEP	695.0	77	840.0	93	555.0	61	904.	717	180	87
	APR-JUL	630.0	77	770.0	94	485.0	60	815.	639	180	87
PALISADES RES INFLOW, ID (1)	APR-JUL	2390.0	72	2930.0	88	1850.0	56	3331.	2288	878	80
HEISE NR, ID	APR-JUL	2550.0	72	3160.0	89	1950.0	55	3561.	2472	1075	85
SHELLEY NR, ID (1)	APR-JUL	3380.0	76	4110.0	93	2650.0	60	4428.	2899	1609	86
BLACKFOOT NR, ID (1)	APR-JUL	3400.0	74	4160.0	90	2640.0	57	4604.	0		
AMER. FALLS RES IN, ID (1)	APR-JUL	1860.0	57	2920.0	90	795.0	25	3242.	1071	1810	70
MILNER, ID	APR-JUL	285.0	23	385.0	31	280.0	23	1228.	43	130	8
KING HILL, ID (1)	APR-JUL	1670.0	55	2620.0	86	710.0	23	3045.	1416	2416	55
MURPHY NR, ID (1)	APR-JUL	1750.0	57	2740.0	89	755.0	24	3092.	1399	2590	57
WEISER, ID (1)	JAN-JUL	5470.0	56	7220.0	74	3730.0	38	9793.	5271	4194	60
	APR-JUL	2640.0	46	4380.0	76	890.0	15	5765.	3085	4194	60
BROWNLEE RES INFLOW	APR-JUL	3130.0	50	5290.0	84	970.0	15	6313.	3522	4561	61
HELLS CANYON, ID (1)	APR-JUL	3250.0	50	5190.0	80	1300.0	20	6493.	3743	4706	63
LOWER GRANITE RES IN, WA (1)	JAN-JUL	21300.0	71	26200.0	87	16300.0	54	30020.	23810	8941	65

Exhibit No. 3
Case No. IPC-E-04-__
G. Said, IPCO
Page 2 of 5

FEB-SEP	21900.0	72	26800.0	88	17000.0	56	30370.	23940	8941	65
APR-JUL	15600.0	72	20500.0	95	10700.0	50	21550.	16730	8941	65

UPPER SNAKE BASINS

Apr-04FINAL

W A T E R S U P P L Y F O R E C A S T S

STREAM AND STATION	PERIOD	FORECAST PROBABLE	%	MAXIMUM	%	RUNOFF MINIMUM	%	AVERAGE RUNOFF	RO PREV YR PERIOD	CURR WY RO TO DATE	
GREY'S RIVER											
PALISADES ABV, WY	APR-SEP	240.0	61	310.0	79	170.0	43	394.	292	87	94
SALT RIVER											
ETNA NR, WY	APR-JUL	198.0	58	300.0	88	97.0	28	342.	176	137	73
HENRYS FORK											
ASHTON NR, ID	APR-JUL	465.0	81	585.0	102	345.0	60	571.	378	366	72
ST. ANTHONY, ID	APR-JUL	550.0	75	770.0	105	335.0	46	734.	382	433	72
REXBURG NR, ID	APR-JUL	1270.0	81	1620.0	104	930.0	60	1559.	394	623	64
FALLS RIVER											
SQUIRREL NR, ID (1)	APR-JUL	315.0	82	380.0	98	245.0	63	386.	187	107	62
TETON RIVER											
ST. ANTHONY NR, ID	APR-JUL	305.0	76	420.0	104	185.0	46	403.	261	157	91
BIG LOST RIVER											
MACKAY RESERVOIR INFLOW, ID	APR-JUL	88.0	62	146.0	103	31.0	22	142.	74	46	62
WILLOW CREEK											
RIRIE RESERVOIR INFLOW	APR-JUL	41.0	48	72.0	84	9.9	12	86.	13	8	34
PORTNEUF RIVER											
TOPAZ, ID	APR-SEP	59.0	62	80.0	84	37.0	39	95.	39	31	50
GOOSE CREEK											
OAKLEY RES INFLOW, ID	APR-JUL	23.0	79	37.0	128	9.7	33	29.	0		
BIG WOOD RIVER											
HAILEY, ID (1)	APR-JUL	152.0	59	240.0	94	66.0	26	256.	229	64	92
MAGIC RESERVOIR INFLOW, ID	APR-JUL	128.0	44	245.0	84	11.4	4	291.	147	46	57
LITTLE WOOD RIVER											
CAREY NR, ID	APR-JUL	45.0	52	75.0	86	15.7	18	87.	56	27	91

MIDDLE SNAKE BASINS

Apr-04FINAL

W A T E R S U P P L Y F O R E C A S T S

STREAM AND STATION	PERIOD	FORECAST PROBABLE	%	MAXIMUM	%	RUNOFF MINIMUM	%	AVERAGE RUNOFF	RO PREV YR PERIOD	CURR WY RO TO DATE	
BRUNEAU RIVER											
HOT SPRING NR, ID	APR-JUL	137.0	66	235.0	113	38.0	18	208.	112	51	69
OWYHEE RIVER											
OWYHEE RES INFLOW, OR	MAR-JUL	485.0	79	695.0	113	275.0	45	613.	158	377	88
OWYHEE RES OUTFLOW	APR-JUL	24.0	11	185.0	85	5.3	2	217.	30	9	5
BOISE RIVER											
TWIN SPRINGS NR, ID (1)	APR-JUL	485.0	76	605.0	95	370.0	58	636.	586	193	90
BOISE NR, ID (1)	APR-JUL	970.0	69	1270.0	90	675.0	48	1414.	1129	455	83
PARMA NR, ID	APR-JUL	85.0	14	270.0	46	46.0	8	593.	195	325	55
S.F. BOISE RIVER											
ANDERSON RNCH RES IN, ID (1)	APR-JUL	350.0	65	455.0	84	245.0	45	542.	393	131	87
MALHEUR RIVER											
DREWSEY NR, OR	MAR-JUL	96.0	87	130.0	118	61.0	55	110.	60	62	79
N.F. MALHEUR RIVER											
BEULAH RES INFLOW, OR (1)	MAR-JUL	70.0	86	87.0	107	54.0	67	81.	46	43	88
PAYETTE RIVER											
HORSESHOE BEND NR, ID (1)	APR-JUL	1150.0	71	1530.0	95	780.0	48	1617.	1490	497	76
EMMETT NR, ID	APR-JUL	705.0	57	1120.0	90	330.0	26	1246.	1177	507	67
DEADWOOD RIVER											
DEADWOOD RES INFLOW, ID (1)	APR-JUL	97.0	72	122.0	91	72.0	54	134.	133	26	78
N.F. PAYETTE RIVER											
CASCADE RES INFLOW, ID (1)	APR-JUL	370.0	75	490.0	99	255.0	52	495.	530	141	67
WEISER RIVER											
WEISER NR, ID (1)	APR-JUL	270.0	69	445.0	114	95.0	24	391.	369	288	74
BURNT RIVER											
HEREFORD NR, OR	MAR-JUL	44.0	86	59.0	116	30.0	59	51.	28	29	91

LOWER SNAKE AND CENTRAL OREGON BASINS

Apr-04FINAL

W A T E R S U P P L Y F O R E C A S T S

STREAM AND STATION	PERIOD	FORECAST PROBABLE	%	MAXIMUM	%	RUNOFF MINIMUM	%	AVERAGE RUNOFF	RO PREV YR PERIOD	CURR WY RO TO DATE
POWDER RIVER										

ROGUE RIVER												
RAYGOLD, OR	APR-SEP	810.0	91	940.0	106	685.0	77	889.	786	1127	82
	JAN-JUL	1450.0	92	1580.0	100	1330.0	84	1584.	1369	1127	82
CHEWAUCAN RIVER											
PAISLEY NR, OR	MAR-JUL	63.0	71	99.0	111	27.0	30	89.	16		
SILVIES RIVER											
BURNS NR, OR	MAR-JUL	89.0	69	153.0	119	26.0	20	129.	31	32	53
	APR-SEP	68.0	69	131.0	132	3.8	4	99.	27	32	53

Forecasts are selected from those prepared by:

National Weather Service
Natural Resource Conservation Service
B.C. Hydro and Power Authority.

Project inflow forecasts have been coordinated with the
U.S. Army Corp of Engineers and U.S. Bureau of Reclamation.

All forecasts are in thousands of acre-feet.
All averages are for the period 1971 through 2000

NOAA/NWS/Northwest River Forecast Center
NNNN

$$

National Weather Service
Northwest River Forecast Center (NWRFC)
5241 NE 122nd Avenue
Portland, Oregon 97230-1089
Telephone: 503-326-7401

Last Modified: April 13, 2004

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-09

IDAHO POWER COMPANY

EXHIBIT NO. 4

G. SAID

PCA Deferral Report

Power Cost Adjustment Summary
April 2003 thru March 2004

		April	May	June	July	August	September	October	November	December	January	February	March	Totals
PCA Revenue														
Normalized Firm Load		991,176	1,033,117	1,143,545	1,352,219	1,422,263	1,206,799	1,112,398	1,030,835	1,162,545	1,229,083	1,162,223	1,106,080	13,952,283
PCA Component Rate		2.156	2.313	2.460	2.460	2.460	2.460	2.460	2.460	2.460	2.460	2.460	2.460	
Revenue at 85%		1,816,429	2,031,075	2,391,153	2,827,490	2,973,952	2,523,417	2,326,024	2,155,476	2,430,882	2,570,013	2,430,208	2,312,813	28,788,931
Load Change Adjustment														
Actual Firm Load - Adjusted	Mwh	1,005,095	1,206,403	1,513,516	1,725,942	1,511,642	1,220,400	1,085,155	1,122,562	1,217,213	1,263,507	1,119,830	1,025,276	15,016,541
Normalized Firm Load	Mwh	991,176	1,033,117	1,143,545	1,352,219	1,422,263	1,206,799	1,112,398	1,030,835	1,162,545	1,229,083	1,162,223	1,106,080	13,952,283
Load Change	Mwh	13,919	173,286	369,971	373,723	89,379	13,601	(27,243)	91,727	54,668	34,424	(42,393)	(80,804)	1,064,258
Expense Adjustment (@ 16.84)		(234,396)	(2,918,136)	(6,230,312)	(6,293,495)	(1,505,142)	(229,041)	458,772	(1,544,683)	(920,609)	(579,700)	713,898	1,360,739	(17,922,105)
Actual Non-QF PCA														
Expense Adjustment	$	(234,396)	(2,918,136)	(6,230,312)	(6,293,495)	(1,505,142)	(229,041)	458,772	(1,544,683)	(920,609)	(579,700)	713,898	1,360,739	(17,922,105)
Purchased Water	$	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Expense-Coal	$	7,211,698	8,167,053	7,001,815	7,007,861	6,500,113	9,420,570	7,572,470	8,366,767	8,185,816	9,085,227	8,692,488	8,938,020	96,149,898
Fuel Expense-Gas	$	219,529	464,928	396,519	1,500,000	928,967	248,489	213,635	278,959	225,146	213,065	237,681	223,887	5,150,805
Non-Firm Purchases	$	2,957,265	4,189,932	14,091,343	31,072,038	21,970,750	9,132,353	5,184,201	3,991,573	12,167,472	4,800,202	3,380,529	4,701,895	117,639,552
Surplus Sales	$	(9,399,118)	(5,354,647)	(2,258,613)	(1,460,784)	(3,880,396)	(7,098,480)	(5,859,374)	(2,150,465)	(6,179,519)	(3,618,339)	(6,381,747)	(17,079,326)	(70,720,809)
Total Non-QF	$	754,977	4,549,130	13,000,751	31,825,620	24,014,291	11,473,891	7,569,704	8,942,151	13,478,306	9,900,455	6,642,849	(1,854,786)	130,297,340
BASE														
Fuel Expense	$	3,341,000	2,293,000	2,843,000	5,076,000	6,445,000	5,587,000	6,026,000	6,909,000	7,127,000	6,051,000	5,051,000	4,737,000	61,486,000
Non-Firm Purchases	$	339,000	1,356,000	1,872,000	2,473,000	1,252,000	615,000	162,000	345,000	844,000	879,000	642,000	296,000	11,075,000
Surplus Sales	$	(3,195,000)	(597,000)	(208,000)	(142,000)	(595,000)	(1,570,000)	(3,022,000)	(3,883,000)	(2,809,000)	(2,978,000)	(2,781,000)	(2,742,000)	(24,522,000)
Surplus Sales Adder	$	(826,063)	(979,683)	(693,151)	(600,808)	(745,141)	(664,245)	(742,240)	(625,640)	(739,128)	(799,267)	(769,197)	(889,476)	(9,074,038)
Net 90% Items	$	(341,063)	2,072,317	3,813,849	6,806,192	6,356,859	3,967,755	2,423,760	2,745,360	4,422,872	3,152,733	2,142,803	1,401,524	38,964,962
Change From Base	$	1,096,040	2,476,814	9,186,902	25,019,428	17,657,433	7,506,136	5,145,944	6,196,791	9,055,434	6,747,721	4,500,046	(3,256,310)	91,332,378
Sharing Percentage		90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Idaho Allocation		85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Non-QF Deferral	$	838,471	1,894,762	7,027,980	19,139,862	13,507,936	5,742,194	3,936,647	4,740,545	6,927,407	5,162,007	3,442,535	(2,491,077)	69,869,269
Actual QF (Includes Meridian Amort & Net Metering)	$	2,356,255	3,448,832	5,441,988	5,862,008	5,505,591	4,203,308	2,805,035	2,169,568	2,224,029	1,965,780	1,911,118	1,745,337	39,638,848
Base QF	$	2,038,265	3,024,735	5,108,325	5,317,475	5,059,785	3,531,295	2,438,425	1,539,895	1,713,885	1,567,845	1,459,785	1,314,445	34,114,160
Change From Base	$	317,990	424,097	333,663	544,533	445,806	672,013	366,610	629,673	510,144	397,935	451,333	430,892	5,524,688
Sharing Percentage		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
Idaho Allocation		85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
QF Deferral	$	270,292	360,482	283,613	462,853	378,935	571,211	311,619	535,222	433,622	338,245	383,633	366,259	4,695,985
Credit From IDACORP Energy	$	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(166,667)	(2,000,000)
Total Deferral	$	(874,334)	57,503	4,753,774	16,608,558	10,746,253	3,623,322	1,755,575	2,953,624	4,763,481	2,763,572	1,229,293	(4,604,299)	43,776,323
Principal Balances														
Beginning Balance ***	$	0	(874,334)	(816,830)	3,936,944	20,545,502	31,291,755	34,915,076	36,670,651	39,624,276	44,387,756	47,151,329	48,380,622	
Amount Deferred	$	(874,334)	57,503	4,753,774	16,608,558	10,746,253	3,623,322	1,755,575	2,953,624	4,763,481	2,763,572	1,229,293	(4,604,299)	43,776,323
Ending Balance	$	(874,334)	(816,830)	3,936,944	20,545,502	31,291,755	34,915,076	36,670,651	39,624,276	44,387,756	47,151,329	48,380,622	43,776,323	
Interest Balances														
Accrual thru Prior Month	$	0	0	(1,459)	(2,738)	3,857	38,167	90,384	148,579	209,696	275,795	349,749	428,328	
Monthly Interest Rate **		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	
Monthly Interest Inc/(Exp)	$	0	(1,457)	(1,361)	6,562	34,243	52,153	58,192	61,118	66,040	73,980	78,586	80,634	508,688
Prior Month's Interest Adjustments	$	0	(1)	82	34	68	64	3	(1)	59	(26)	(7)	3	278
Total Current Month Interest	$	0	(1,459)	(1,280)	6,595	34,310	52,217	58,195	61,117	66,099	73,954	78,579	80,638	508,965
Interest Accrued to date	$	0	(1,459)	(2,738)	3,857	38,167	90,384	148,579	209,696	275,795	349,749	428,328	508,965	
Balance in All Accounts	$	(874,333)	(818,289)	3,934,206	20,549,359	31,329,922	35,005,461	36,819,230	39,833,972	44,663,551	47,501,078	48,808,949	44,285,289	44,285,289
Beginning True-Up of True-Up Balance	$	38,658,298	38,658,298	38,512,422	35,355,315	30,514,646	25,633,569	21,449,248	17,978,914	14,760,352	11,408,951	7,700,962	3,961,110	
Monthly Interest Rate		2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	
Monthly Interest	$	64,431	64,431	64,187	58,926	50,858	42,723	35,749	29,965	24,601	19,015	12,835	6,602	
Monthly Collection	$	0	274,737	3,221,294	4,899,594	4,931,935	4,227,044	3,506,083	3,248,526	3,376,002	3,727,004	3,752,687	3,411,019	
Monthly Collection Applied To Interest	$	0	128,861	64,187	58,926	50,858	42,723	35,749	29,965	24,601	19,015	12,835	6,602	
Monthly Collection Applied To Balance	$	0	145,876	3,157,107	4,840,668	4,881,077	4,184,322	3,470,334	3,218,561	3,351,401	3,707,989	3,739,852	3,404,417	
Ending True-Up of the True-Up Balance	$	38,658,298	38,512,422	35,355,315	30,514,646	25,633,569	21,449,248	17,978,914	14,760,352	11,408,951	7,700,962	3,961,110	556,693	

* Negative amounts indicate benefit to the ratepayers.
** Interest rate changed per IPUC Order 29158.
***Beginning balance per IPUC Order 29243.

EXHIBIT NO. 4
CASE NO. IPC-E-04-__
G. SAID, IPCO
Page 1 of 1

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-09

IDAHO POWER COMPANY

EXHIBIT NO. 5

G. SAID

IPUC Order No. 29334

Office of the Secretary
Service Date
September 16, 2003

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT A POWER COST ADJUSTMENT (PCA) RATE FOR ELECTRIC SERVICE FROM MAY 16, 2003 THROUGH MAY 15, 2004.	)	CASE NO. IPC-E-03-5 ORDER NO. 29334

In June 2003, the Commission urged the parties to move expeditiously so that contested issues involving the proper amount of normalized energy to calculate true-up and class deferral rates could be resolved in a timely manner. Order No. 29258 at 2. Following several months of negotiations, the parties reached an agreement regarding the outstanding issues in this PCA docket. On August 20, 2003, Idaho Power Company filed a Motion for Acceptance of Settlement on behalf of itself, Commission Staff, the Industrial Customers of Idaho Power (ICIP), and the Idaho Irrigation Pumpers Association (Irrigators). After reviewing the record and the provisions of the Stipulation, the Commission accepts the Stipulation as a fair, just and reasonable resolution to the contested issues remaining in this case.

PROCEDURAL BACKGROUND

Idaho Power is an electric utility engaged in the generation, transmission, distribution and sale of electric energy and provides retail electric service to approximately 380,000 customers in southern Idaho and eastern Oregon. On April 15, 2003, Idaho Power Company filed an Application to decrease its electric rates under the annual Power Cost Adjustment (PCA) mechanism first approved by the Commission in 1993. In Order No. 29243, the Commission approved the rates proposed in the Company's Application (with one adjustment) effective May 16, 2003, subject to refund and interest. In addition, the Commission set a prehearing conference to schedule six disputed issues valued at approximately $5.1 million for evidentiary hearing. These six issues included: 1) pricing of real-time transactions between Idaho Power and IDACORP Energy (IE); 2) recovery of IE-Tri State Transmission costs; 3) Company sharing of the anticipated FERC settlement; 4) continuance of payment for IE management contract benefits; 5) the proper amount of normalized energy to compute the true-up rate; and 6) the

EXHIBIT NO. 5
CASE NO. IPC-E-04-__
G. SAID, IPCO
Page 1 of 7

proper amount of normalized energy to compute the rates to be paid on PCA amounts deferred from the prior PCA period. Order No. 29243 at 10.

At the prehearing conference held May 30, 2003, Idaho Power, Staff, the Irrigators, and ICIP entered appearances. Although the Commission had intended to immediately set a date for an evidentiary hearing at the prehearing conference, the parties proposed an alternative with the hope that an evidentiary hearing could be avoided.

To further explore the possibility of settlement and achieve a quicker resolution than might be available through an evidentiary hearing, the Commission adopted the parties' proposal to move the following four issues to Case No. IPC-E-01-16 for further proceedings: 1) pricing of real-time transactions between Idaho Power and IE; 2) recovery of IE-Tri State Transmission costs; 3) Company sharing of the anticipated FERC settlement; and 4) continuance of payment for IE management contract benefits. Order No. 29258. Because real-time affiliate pricing, transmission costs, and resolution of outstanding IE matters are already part of ongoing settlement discussions in Case No. IPC-E-01-16, the parties felt it would be more efficient to consolidate these issues under that case number. The Commission directed the remaining two issues involving the proper amount of normalized energy to calculate true-up and class deferral rates to continue under this case number (IPC-E-03-5). *Id.*

PROPOSED SETTLEMENT

According to the Stipulation, the parties discussed three major issues. First, the parties sought to determine the appropriate kWh sales level to use as the denominator for computing the true-up rate for this case and future PCA periods. Second, Idaho Power proposed inclusion of a carrying charge on the unamortized balances during future true-up collection and refund periods. The ICIP and Irrigators were also concerned that collection of their allocated true-up amounts may be too great if 1993 normalized sales were used rather than the 2000 normalized sales levels initially used to compute the deferral amount.

In the signed settlement document, all four parties agreed that:

1. The currently-approved PCA rates will remain in effect through May 15, 2004, i.e., the remainder of this 2003-2004 PCA year.

2. The PCA methodology will be modified to include a true-up of the true-up. At the time the Company makes its April 2004 PCA application, the Company will compute the amount of any under-collection or over-collection of the $38.7 million true-up amount approved by the

Commission in Order No. 29243. This amount will then be applied as a credit (or debit) against the 2004-2005 PCA ("true-up of the true-up"). The approved PCA methodology will thereafter include a true-up of the true-up for each succeeding PCA year.

3. Carrying charges on the unamortized balance at the rate of 2% per annum (the currently approved rate for the true-up deferral balance accumulation) will be included during the 2004-2005 true-up of the true-up period. Thereafter, carrying charges will be determined for either the true-up collection period or true-up refund period, whichever occurs from year to year. Idaho Power will compute the carrying charges using the same interest rate the Commission annually determines to be appropriate for the true-up deferral balance accumulation. The methodology for computing carrying costs is more particularly described in Appendix 1 to the Settlement.

4. For Schedule 7, 19, and 24 customers, the true-up of the true-up will not be applied to the $16 million total of class-specific adders from the 2002-2003 PCA year. Instead, the customers in those classes will receive a credit during the 2004-2005 PCA year which will be computed based on the difference between the true-up rate credit computed under the currently-approved PCA rate (using 1993 sales data) and the rate credit that would have been computed using 2000 normalized kilowatt-hour sales for each of the three classes. Attachment 2 to the Settlement describes this process in more detail and shows the 2004-2005 rate credit on a cents per kilowatt-hour for Schedule 7, 19 and 24 customers.

5. Beginning with the April 2004 PCA application, the Company will make its annual PCA application utilizing its best estimate of the total Idaho jurisdictional sales that will be made during the ensuing PCA year rather than a sales constant set in a general revenue requirement case. The intent of this change to the approved PCA methodology is to set a firm sales denominator that will minimize the magnitude of subsequent true-ups of the true-up.

According to the Motion for Acceptance of Settlement, all parties to this case are signatories to the Stipulation, which is intended to be an integrated document. Furthermore, the parties agree that the Stipulation is in the public interest and all the terms of the Stipulation are fair, just and reasonable. The parties request the Commission issue an Order accepting the Stipulation in settlement of all remaining issues in this case. As a result, the parties do not believe that an evidentiary hearing is required according to Procedural Rule 274.

COMMISSION FINDINGS AND DISCUSSION

Pursuant to Commission Rule 274 we shall decide whether to accept the Stipulation based on the record currently before us. IDAPA 31.01.01.274. The record is substantial and all parties that participated in the settlement negotiations in this case have signed this Stipulation. Accordingly, we find further proceedings are not necessary for us to determine whether we should accept this Stipulation.

Normalized kWh Sales Level

The present PCA methodology uses the 1993 normalized kWh sales level as the denominator for computing the true-up rate. Because the last two PCA years deviated from the methodology by using 1999 and 2000 normalized sales levels respectively, Staff and Irrigators argued for using more recent normalized sales data during the 2003-2004 PCA period as well. Due to variations in energy consumption, actual sales to Idaho jurisdictional customers during any PCA year will never match the Commission-approved 1993 denominator of 10,802,636 MWh. Order No. 25880.[1] Consequently, the parties agreed to modify the current PCA methodology to eliminate under-collection, over-collection, under-refunding, and over-refunding of the authorized true-up amounts by "truing up the true-up." Beginning in its 2004 PCA application, the Company will make its annual PCA application using its best estimate of the total Idaho jurisdictional sales that will be made during the ensuing PCA year rather than using sales constant set in a general rate case.

After reviewing the Stipulation signed by the parties, the Commission finds that it embodies an appropriate resolution of the proper amount of normalized energy to calculate the true-up of the true-up rate in this case and true-up rates on a going forward basis. We also find that it is appropriate for the Company's future PCA applications to use a best estimate of total Idaho jurisdictional sales for the upcoming PCA year to minimize the magnitude of the true-up of the true-up. The Stipulation's true-up of the true-up will then eliminate any remaining imbalance. Thus, ratepayers will pay for the actual amount of kWh sold by Idaho Power to meet native load requirements – no more, no less. The Commission finds that these changes will allow an up-to-date normalized sales level to be used even if several years have passed since a rate case. The Commission believes that these permanent changes to the PCA methodology will

[1] This Order was later adjusted in Case No. IPC-E-98-5 for a change in the FMC contract. Order No. 27516.

better ensure Idaho Power and its customers will both be treated fairly, particularly during periods of volatile power supply costs and energy consumption.

Class Deferral Rates

Because payment of their prior true-up amounts were deferred, customers receiving service under Schedule 7 (Small General Service), Schedule 19 (Large Power Service), and Schedule 24 (Irrigation Service) have class-specific adders that are still to be recovered during the 2003-2004 PCA year. As a result and unlike most PCA years, these classes have a different PCA true-up rate than do the other customer classes. The Irrigators and ICIP were concerned that collection of their allocated true-up amounts may be too great if 1993 normalized sales levels were used to compute the deferral amount rather than the 2000 normalized sales levels initially used during the 2002-2003 PCA year.

As part of the Stipulation, the parties agreed that the currently-approved PCA rates should remain in effect through May 15, 2004, i.e., the remainder of this 2003-2004 PCA year. Furthermore, Schedule 7, 19, and 24 customers that have class-specific adders will receive a credit during the 2004-2005 PCA year based on the difference between the true-up rate credit computed under the currently-approved PCA (using 1993 sales data) and the rate credit that would have been computed using 2000 normalized kilowatt-hour sales for each of the three classes.

To minimize confusion and implementation issues, the Commission agrees that rates should remain constant through this current PCA year. Given the unique circumstances of this case, we believe the Stipulation reasonably resolves the concerns of the parties regarding the rates used to collect class deferrals. Thus, we find it reasonable and appropriate to adopt the parties' settlement on this issue.

Carrying Charges

The present PCA methodology does not allow computation of carrying charges during the true-up collection or true-up refund period. When the PCA was first developed, the parties agreed that over time the true-up collections and refunds would offset each other. Thus, computation of carrying charges during the term of actual rate recovery would be symmetrical and therefore unnecessary. As noted in the Stipulation, true-up collections in recent years have not been offset by large true-up refunds. Thus, the parties have agreed to include a carrying charge on the unamortized balance during true-up collections and refunds using the same interest this Case No. IPC-E-03-5. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 16th day of September 2003.

PAUL KJELLANDER, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

O:IPCE0305_ln4

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-09

IDAHO POWER COMPANY

EXHIBIT NO. 6

G. SAID

Original & Legislative Schedule 55

SCHEDULE 55
POWER COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers served under the Company's schedules, to the primary portion of the FMC Special Contract, and to all other Idaho retail Special Contracts. These loads are referred to as "firm" load for purposes of this schedule.

BASE POWER COST

The Base Power Cost of the Company's rates is computed by dividing the Company's power cost components by firm kWh load. The power cost components are the sum of fuel expense and purchased power expense (including purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue. The Base Power Cost is 0.7315 cents per kWh.

PROJECTED POWER COST

The Projected Power Cost is the Company estimate, expressed in cents per kWh, of the power cost components for the forecasted time period beginning April 1 each year and ending the following March 31. The Projected Power Cost is 1.0092 cents per kWh.

TRUE-UP AND TRUE-UP OF THE TRUE-UP

The True-up is based upon the difference between the previous Projected Power Cost and the power costs actually incurred. The True-up of the True-up is the difference between the previous years approved True-Up revenues and actual revenues collected. The total True-up is 0.3540 cents per kWh.

POWER COST ADJUSTMENT

The Power Cost Adjustment is 90 percent of the difference between the Projected Power Cost and the Base Power Cost plus the True-ups.

The monthly Power Cost Adjustment applied to the Energy rate for Irrigation Service (Schedules 24 and 25) is 0.5228 cents per kWh, for Small General Service (Schedule 7) is 0.5850 cents per kWh and Large Power Service (Schedule 19) is 0.5817 cents per kWh. The monthly Power Cost Adjustment applied to the Energy rate of all other metered schedules and Special Contracts is 0.6039 cents per kWh. The monthly Power Cost Adjustment applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times 0.6039 cents per kWh.

EXPIRATION

The Power Cost Adjustment included on this schedule will expire May 31, 2005.

SCHEDULE 55
POWER COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers served under the Company's schedules, to the primary portion of the FMC Special Contract, and to all other Idaho retail Special Contracts. These loads are referred to as "firm" load for purposes of this schedule.

BASE POWER COST

The Base Power Cost of the Company's rates is computed by dividing the Company's power cost components by firm kWh load. The power cost components are the sum of fuel expense and purchased power expense (including purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue ~~and FMC secondary load revenue~~. The Base Power Cost is ~~0.5238~~ 0.7315 cents per kWh.

PROJECTED POWER COST

The Projected Power Cost is the Company estimate, expressed in cents per kWh, of the power cost components for the forecasted time period beginning April 1 each year and ending the following March 31. The Projected Power Cost is ~~0.7971~~1.0092 cents per kWh.

TRUE-UP AND TRUE-UP OF THE TRUE-UP

The True-up is based upon the difference between the previous Projected Power Cost and the power costs actually incurred. The True-up of the True-up is the difference between the previous years approved True-Up revenues and actual revenues collected. The total True-up is ~~0.3579~~ 0.3540 cents per kWh.

POWER COST ADJUSTMENT

The Power Cost Adjustment is 90 percent of the difference between the Projected Power Cost and the Base Power Cost plus the True-ups.

The monthly Power Cost Adjustment applied to the Energy rate for Irrigation Service (Schedules 24 and 25) is ~~1.3159~~0.5228 cents per kWh, for Small General Service (Schedule 7) is ~~0.8477~~0.5850 cents per kWh and Large Power Service (Schedule 19) is ~~0.8217~~0.5817 cents per kWh. The monthly Power Cost Adjustment applied to the Energy rate of all other metered schedules and Special Contracts is 0.6039 cents per kWh. The monthly Power Cost Adjustment applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times 0.6039 cents per kWh.

EXPIRATION

The Power Cost Adjustment included on this schedule will expire May 31, ~~2004~~2005.

EXHIBIT NO. 6
CASE NO. IPC-E-04-__
G. SAID, IPCO
Page 2 of 2

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-04-09

IDAHO POWER COMPANY

EXHIBIT NO. 7

G. SAID

Summary of Revenue Impact

Idaho Power Company
Summary of Revenue Impaci
State of Idaho
Normalized 12-Months for Test Year 2003

Line No	Tariff Description	(1) Rate Sch. No.	(2) 2003 Avg. Number of Customers	(3) 2003 Sales Normalized (kWh)	(4) Current PCA Including Extra Charges Revenue	(5) Revenue Adjustments	(6) Proposed 06/01/04 PCA Including Credits Revenue	(7) Avg. Mills Per KWH	(8) Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1	335,605	4,141,393,426	239,299,289	0	239,299,289	57.78	0.00%
2	Small General Service	7	32,316	265,335,667	19,047,726	(697,038)	18,350,688	69.16	(3.66)%
3	Large General Service	9	17,415	3,014,426,986	125,873,136	0	125,873,136	41.76	0.00%
4	Dusk to Dawn Lighting	15	-	5,872,586	1,425,148	0	1,425,148	242.68	0.00%
6	Large Power Service	19	105	1,978,824,237	71,323,573	(4,749,179)	66,574,394	33.64	(6.66)%
7	Agricultural Irrigation Service	24	13,517	1,620,930,931	81,621,405	(12,855,604)	68,765,801	42.42	(15.75)%
8	Unmetered General Serv.	40	1,224	16,054,942	1,004,661	0	1,004,661	62.58	0.00%
9	Street Lighting	41	1,432	17,912,039	1,918,303	0	1,918,303	107.10	0.00%
10	Traffic Control Lighting	42	58	9,384,218	340,826	0	340,826	36.32	0.00%
11	*Total Uniform Tariffs*		401,672	11,070,135,032	541,854,067	(18,301,821)	523,552,246	47.29	(3.38)%
	Special Contracts:								
12	Micron	26	1	636,967,670	19,384,935	0	19,384,935	30.43	0.00%
13	J R Simplot	29	1	186,684,665	5,759,960	0	5,759,960	30.85	0.00%
14	DOE	30	1	203,084,146	5,848,839	0	5,848,839	28.80	0.00%
15	*Total Special Contracts*		3	1,026,736,481	30,993,734	0	30,993,734	30.19	0.00%
16	***Total Idaho Retail Sales***		401,675	12,096,871,513	572,847,801	(18,301,821)	554,545,980	45.84	(3.19)%

EXHIBIT NO. 7
CASE NO. IPC-E-04-__
G. SAID, IPCO