LISA D. NORDSTROM
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0314
IDAHO BAR NO. 5733

Street Address for Express Mail:
472 W. WASHINGTON
BOISE, IDAHO 83702-5983

Attorney for the Commission Staff

RECEIVED ☒
FILED ☐
2003 MAY -8 PM 4:38
IDAHO PUBLIC
UTILITIES COMMISSION

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** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Lisa D. Nordstrom, Deputy Attorney General, and in response to the Notice of Application, Notice of Modified Procedure and Notice of Comment Deadline issued in Order No. 29229 on April 17, 2003, submits the following comments.

On April 15, 2003, Idaho Power Company (Idaho Power, Company) filed an Application with the Commission for authority to decrease Power Cost Adjustment (PCA)[1] rates. Idaho Power supplies electricity to approximately 380,000 customers in southern Idaho. The PCA mechanism is traditionally comprised of two major components: 1) true up of abnormal Company power supply costs collected during the preceding twelve (12) months, and 2) the

[1] In March 1993, the Commission authorized Idaho Power to file proposed Power Cost Adjustment (PCA) surcharges or rebates to take effect in May each year. Order No. 24806 (Case No. IPC-E-92-25).

projection[2] of the next year's power supply costs based on expected[3] Snake River stream flows and storage. This year the PCA contains a third component for amounts small commercial, industrial and irrigation customers carried over from last year to this year, thus reducing the amount of their respective rate decreases. The Company's request, if approved, would decrease its overall revenues by approximately $114 million and lower overall rates by an average of 18.2% effective May 16, 2003.

STAFF ACCOUNTING ANALYSIS

Staff performed an audit of the Company's revenues and expenses associated with the proposed surcharge. The audit included a detailed review of: 1) purchased power and power sales; 2) Commission Orders allowing additional items to flow through the PCA accounts; 3) the implementation of the Astaris Voluntary Load Reduction Stipulation and payments; 4) the natural gas and transportation purchases for the Danskin facility; 5) the IDACORP Energy proposed settlement; 6) the Risk Management Committee process and documentation; and 7) other true up expenses and credits. Staff presents the following findings and recommendations.

Power Supply Purchases and Sales

Staff has performed a detailed audit of the Company's electricity purchases and sales made during the last PCA year. Idaho Power purchased from and sold day-ahead and real-time energy to only IDACORP Energy (IE) through July 31, 2002. Staff verified that the day-ahead energy purchased from IE was priced at the Mid-C index as authorized by the Commission in past Orders.[4] After July 31, 2002, Idaho Power used in-house traders to buy and sell energy using a variety of counter parties, but continued to supply IE with load following[5] purchases and sales through December 31, 2002. These transactions were associated with a load following contract IE had with a third party.

---

[2] The Company may recover 90 percent of the difference between the projected power cost and the Commission's approved base power cost. Order No. 25880.

[3] This forecast is based upon an April 1 projection of April through July Brownlee inflow.

[4] See Order No. 28852.

[5] Load following requires a service provider to make available energy supplies to meet moment-to-moment demand in the distribution system served by its customer, and/or keep generating facilities available to insure that it is providing neither too little nor too much energy to supply the customer's needs.

In its Application, the Company proposes to price the real-time transactions with IE based on the weighted average of all IE real-time transactions. This methodology is consistent with what the Company used in the last PCA.[6] Staff has reviewed the Company's analysis and confirmed that customers receive a greater benefit using this methodology during three of the four months Idaho Power used IE to manage its real-time needs than they would have had with the Federal Energy Regulatory Commission's (FERC) proposed high-low methodology.[7] During the fourth month, July 2002, the energy needs were more expensive under the weighted average methodology than under the high-low methodology. This result may be due to the winding down of trading operation at IE with fewer transactions to calculate the weighted average from June 2002 forward. As of this date, Idaho Power's case before the FERC has not been resolved as to the pricing mechanism for real-time power. In its March 17, 2003 proposal to the FERC, Idaho Power committed to give its customers the benefit of the best mechanism. The Company stated:

> The Settlement revises the real-time pricing in the Agency Agreement to use the real-time methodology preferred by the IPUC or the Applicants' May 14, 2001 compliance filing proposal, whichever is more favorable to Idaho Power over the life of the Agreement.[8]

In other words, the Company proposed to the FERC that the customers receive the best treatment possible to help avoid gaming the system by IE. Staff recommends that the Commission accept the first three months of real-time pricing as proposed by the Company using the weighted average methodology because it is more favorable for customers. For the month of July, Staff recommends that the Company use the high-low methodology for calculating the real-time prices because it provides greater customer benefits than the weighted average methodology. Staff believes that in this case, it is reasonable to compare methodologies on a monthly basis given the purpose of the settlement to resolve pricing discrepancies between Idaho

---

[6] During the PCA period ending in March 2002, the Company proposed changing its real-time transaction pricing from the FERC methodology to a weighted average methodology. See Case No. IPC-E-02-2 and IPC-E-02-3 and Order No. 29026.

[7] The FERC proposed that real-time purchases by Idaho Power from IE be priced at the lowest price IE was willing to sell to another entity during that hour. Conversely, real-time sales from Idaho Power to IE shall be priced at the highest price IE pays for power to another entity during that hour. The Company states that this method is not as advantageous to customers as the weighted average method. The Company has performed an analysis that shows customers benefit more using the weighted average method during three of the four months during the PCA period Idaho Power's real-time needs were managed by IE.

[8] The Company's settlement proposal was sent to the FERC on March 17, 2003 by the Company attorney Gary Morgans. The section referred to by Staff is found on page 3 of the settlement proposal.

Power and IE. The Company assured FERC that it would use the methodology most favorable for Idaho Power and its customers over the life of the agreement. A difference in methodologies for the month of July 2002 is reasonable due to the change in operations resulting from the winding down of trading at IE. Ratepayers should receive the benefit on a monthly basis and not be penalized for changes in operations at IE. After the month of July 2002, it is no longer necessary to compare methodologies because Idaho Power began managing its own real-time needs. Staff recommends that $50,242.47 be removed from July 2002 purchases and sales to reflect this pricing procedure. After jurisdictional and Company sharing, customers would receive a benefit of $38,435.49.

While conducting its audit, Staff identified a missing payment from IE to Idaho Power relating to a contract termination with Montana Power. When Staff asked the Company why the payment had not been made, it was stated that IE personnel had inadvertently forgotten and would forward the amount immediately. Staff proposes to flow through the $63,229.16 relating to the IE payment to customers during the month of September 2002 when it should have been made. After jurisdictional and Company sharing, customers would receive a benefit of $48,370.32.

Astaris Voluntary Load Reduction Payments and Credits

On April 10, 2001 in Order No. 28695, the Commission approved a Letter Agreement between Idaho Power and Astaris to receive payments from Idaho Power for a 50 MW firm load reduction at its Pocatello manufacturing facility. This load reduction was made available to Idaho Power for 24 months beginning April 1, 2001 and ending March 31, 2003. In Case No. IPC-E-01-43, the Commission authorized an investigation regarding payment amounts and the circumstances surrounding the Letter Agreement. As a result of that investigation, the Commission issued Order No. 29050 authorizing a settlement and stipulation between all the parties. The settlement provided that the Voluntary Load Reduction (VLR) payments Idaho Power makes to Astaris under the terms of the Letter Agreement will be reduced by $5,000,000. The benefit of this reduction will flow through Idaho Power's PCA mechanism to the general body of ratepayers. Idaho Power has also agreed that its jurisdictional PCA share of the VLR savings, approximately $425,000, shall be distributed to Idaho ratepayers through the PCA mechanism. Finally, the parties agreed that the remaining $1 million Astaris take-or-pay credit will be included in the 2002/2003 PCA true p balance without any reduction, as will the

$275,663 adjustment for uncollected Astaris take-or-pay obligations. Staff has reviewed the payments Idaho Power made to Astaris and verified that the amounts were paid and passed through the PCA in accordance with the Commission Orders as set out in the stipulation.

Natural Gas and Transportation Purchases

In March 2001 Idaho Power entered into a long-term agreement with Northwest Pipeline to receive firm gas transportation from the Sumas gas delivery region to its Danskin facility in Mountain Home, Idaho.[9] In addition to that contract, the Company signed a short-term agreement with IGI Resources (IGI) to purchase gas and resell any of its unused transportation. As the ending date of the IGI contract approached in October 2002, Idaho Power began to search for a new service provider to manage the Company's transportation and nomination needs, plus provide the natural gas necessary to run its facility. According to the Company, IGI was the only company available that could meet all of Idaho Power's needs and credit requirements. The Company entered into another short-term contract with IGI to manage its transportation and provide various other services. The new IGI contract expires in March 2004. Staff recommends that the Company undertake an RFP process before the expiration of the current IGI contract to see if IGI or other marketers could provide the same or better services at a price that is more advantageous for customers.

IDACORP Energy Proposed Settlement

In September 2002 Idaho Power announced that it had failed to properly disclose three of its wholesale transactions with IE to the FERC. The three transactions included ancillary services and power sales that IPC provided to IE. Idaho Power has since reported the transactions and is working with the FERC enforcement division to develop an acceptable settlement amount to be passed on to customers.

Idaho Power believes a settlement with the FERC is imminent and recommends that a portion of the settlement proceeds flow through the PCA accounts to customers. The proposed settlement is based on the net revenues IE received from the three contracts less the amounts IE has already paid to Idaho Power for these services. According to the Company, the total value of

[9] On March 22, 2001 the Company entered into an agreement with Northwest Pipeline to transport gas from the Sumas region to the Company's Danskin facility. The Contract provides firm transportation until February 28, 2007.

the three agreements is $5,826,186. During this PCA period and the prior period, Idaho Power has already received a total of $4,043,866 relating to the three contracts. The proposed $1,782,320 settlement is the difference between these two amounts.

Staff has reviewed the proposed settlement and agrees that it is appropriate for customers to receive a benefit in the current PCA. The settlement involves three contracts. Idaho Power claims one of the contracts, the Truckee-Donner contract, has no additional effect on the PCA because Idaho Power has already received the full value of the contract, $5,730. Staff has identified the Truckee-Donner agreement as one that will be further explored in the IPC-E-01-16 process. Idaho Power agrees that IPC-E-01-16 is the proper case for this review. The final determination of issues and any settlement amounts will be presented for the Commission decision in Case No. IPC-E-01-16.

The second contract relates to a load following agreement with Montana Power for capacity and energy. Idaho Power proposes to credit customers $1,165,191.47 before any jurisdictional or Company sharing for the previously unpaid benefits IE received from this contract. Staff accepts this adjustment as reasonable for this PCA.

The final contract relates to spinning reserves[10] the Company provided to IE for the Tri-State contract. In its proposed settlement, Idaho Power and IE recommend that Idaho Power pay $428,625 for transmission costs that IE allegedly incurred while servicing this contract. Staff does not believe it is reasonable to charge customers this amount under the PCA mechanism because it relates to transmission payments that are not normally included in the PCA mechanism. Transmission costs and benefits have been identified as an issue to be further considered in IPC-E-01-16. If Idaho Power agrees to this settlement payment with the FERC, then Idaho Power should bear the cost of that transmission. Staff recommends removal of the $428,625 relating to the transmission payments that Idaho Power would have to bear under the proposed settlement until the proper treatment of transmission is resolved in IPC-E-01-16.

The Company proposes allocating the settlement between Idaho and its other customers based on the current Idaho jurisdictional allocation factor of 85%. In addition, the Company recommends sharing the remaining amount based on the 90/10 split normally used when allocating surplus power sales. Staff agrees that customers should receive the benefits of the

---

[10] Spinning reserve is back-up energy production capacity that can be made available to a transmission system with only a few minutes notice.

proposed settlement, but believes that customers should receive the entire Idaho jurisdictional share. It is not appropriate for the Company to fail in its regulatory responsibilities and receive a financial benefit. This recommendation is consistent with past Commission practice for settlements and separately ordered items where 100% has flowed through the PCA.[11] In short, Staff recommends that Idaho customers receive the entire settlement amount allocated to Idaho without the transmission payments referenced above. Staff Attachment A shows Staff's recommended PCA treatment of the proposed settlement without Company sharing. By removing the transmission payments and eliminating the Company's share of the settlement benefit, Staff's recommendation reduces the power supply costs in Idaho by $515,828.42.

The other IE issue addressed by the Company is the $2 million guaranteed payment from IE to Idaho Power to ensure that customers would receive at least some benefit from the IE-Idaho Power Management Services Agreement (Agreement). This amount was guaranteed to customers by the stipulation in Case No. IPC-E-00-13 and Order No. 28596. Staff believes this amount should continue to flow to customers as stated in the stipulation. Order No. 28596 refers to the settlement drafted by Idaho Power and states "Stipulation Section No. 1.2 provides that this $2,000,000 will flow back to Idaho customers annually coincidentally with Idaho Power's PCA. This annual reduction will continue until new Idaho Power tariff rates are implemented in the next rate case."[12] In the same Order the Commission stated, "We find the identified cost savings and related benefits to customers to be an important factor in assessing the merits of the underlying Agreement."[13] Staff believes that the Company should continue to fulfill its obligation to customers and flow the benefit amount back until the tariff rates are set again in the next rate case. Staff recommends the Commission require the Company to book the $2 million amount in monthly installments until the next rate case.

---

[11] The Commission has always reserved the option of flowing costs through the PCA at 100% instead of 90%. See Order No. 25131 which allowed CSPP costs to be flowed through to customers at 100% and Order No. 29050 which authorized settlement payments made to Astaris to be flowed through to customers at 100%. In Order No. 28596, the Commission ordered the $2 million settlement to be passed directly to customers without sharing. The Commission has also on occasion allowed Idaho Power to collect 100% of its costs without sharing. For example, in Orders No. 29147, 29085, and 28992 the Commission ordered intervenor funding to be passed on to customers at 100%. In Order No. 28753 the Commission authorized the Company to collect 100% of the mobile home metering costs through the PCA.

[12] Order No. 28596 at 6.

[13] Order No. 28596 at 10.

Other True Up Expenses and Credits

Staff has also reviewed two other items the Company proposes to flow through the PCA to customers. These items are intervenor funding and mobile home metering costs. Staff has reviewed the Commission Orders that required the costs to flow through the PCA and found that they were recorded properly. Therefore Staff recommends that they be passed on to customers as proposed by the Company.

Risk Management Committee Review

As part of the audit and the ongoing IPC-E-01-16 case, Staff has reviewed documentation provided by the Risk Management Committee (RMC). At this time Staff is generally pleased with the work the RMC has done with the 3-Tier risk management system and the documentation and analysis performed each month. The documentation is much better than that previously provided and it appears the Company performs a thoughtful and careful analysis on a regular basis. Idaho Power has made many improvements to the Operating Plan (OP Plan) presented to the RMC on a monthly basis. One such improvement made for the January 14, 2003 RMC meeting identified the hedges by month, with heavy load-hour and light-load hour splits. The detail also presents the total hedge position and any orders to fill.

Staff is concerned that the RMC occasionally authorizes a transaction to be completed but which is not undertaken by the next RMC meeting or identified in the RMC minutes or supporting documentation. There are two reasons that such transactions may not have been completed. First, the Company could find no counter party willing to accept the transaction at the proposed price. This could be due to an illiquid market or that the price the Company is offering is to too high or low. Second, before the transaction is carried out, Company personnel may be presented with new information that makes the transaction unnecessary or imprudent. Staff recommends that the Company document in the RMC meeting minutes the reasons why authorized transactions are not carried out. Additional documentation of e-mail orders or changes to orders also need to be included with the RMC minutes. This will allow faster verification of power supply transactions in future PCA filings. Idaho Power has been open to such suggestions in the past and its employees have actively sought to improve the OP Plan.

STAFF ENGINEERING ANALYSIS

True Up

Each PCA true up calculation includes the previous year's abnormal actual power supply costs that are netted against revenue based on the previous year's forecasted rate. This net amount is calculated monthly on the true up spreadsheet and deferred for recovery in the following year's PCA. The calculated deferrals for April 2002 through March 2003 are shown on Company Exhibit No. 3. Staff has verified the method and calculation of those amounts. As previously discussed in these comments, Staff recommends some changes to the true up spreadsheet input amounts. Staff's proposed changes are labeled "Staff Adjustments" and are shown on line 48 of Staff's true up spreadsheet. Staff's true up spreadsheet is Attachment B, pages 1 and 2, to these comments. Without these changes Staff's spreadsheet produces the same result as Company Exhibit No. 3. With these changes Staff calculates the amount of the true up to be $38,103,009.

Projection (Forecast)

Each year's PCA also includes a projection of power supply costs for the coming year. The projection uses forecasted inflows to Brownlee Reservoir for the April through July period[14] in a power supply cost regression formula. This year's forecast of 3.3 million acre-feet is only 53 % of normal. When this level of forecast runoff is used in the regression formula, an expected PCA expense of $111,209,454 is calculated for the coming year. This is the same amount calculated by the Company is its filing. The graphic representation of this calculation is shown on Attachment C to these comments. Staff agrees with the Company that this amount is approximately $38.1 million above normal annual Company Power Supply Costs.

Carry-Over Amounts

In last year's PCA Case, Case No. IPC-E-02-2 and -3, the Commission ordered a portion of the extraordinarily high power supply costs for three customer classes be carried over to this year. Order Nos. 29026 and 29065. The three customer groups are: Schedule 7 - Small General Service Customers, Schedule 19 - Large Power Service Customers and Schedule 24 - Irrigation

[14] This forecast is prepared and published annually by the National Weather Service Northwest River Forecast Center.

Customers. As a result of this action the three customer groups paid lower PCA rates than did other customers last year. Consequently, these same three customer groups will pay higher PCA rates than other customers this year. Interest has also accumulated on the carry-over balances at 6%. By Commission Order No. 28992, the irrigation amount also includes the recovery of some intervenor funding. Attachment D shows the break down of these costs.

PCA Rates

Attachment E shows the calculation of 2003-2004 PCA rates. Lines 1 through 6 show the calculation of the portion of the PCA rate associated with the forecast. The rate is 90% of the expected above normal system power supply costs divided by system normalized energy. This rate is 0.2460 ¢/Kilowatt-hour (¢/kWh) and is exactly the same as the rate calculated by the Company in its filing.

Line 8 calculates that portion of the PCA rate that comes from the 2002-2003 true up. When Company proposed true up dollars and normalized energy (Megawatt-hours, MWh) are used in this calculation, Staff duplicates the true up rate proposed by the Company of 0.3583 kWh. However, Staff has adjusted the true up amount to $38,103,009 as previously discussed and Staff proposes continued use of a more appropriate level of energy consumption, 11,920,360 MWh, in determining the rate. Fewer dollars divided by more energy produce a lower rate of 0.3195 ¢/kWh.

Line 10 shows this year's total Staff recommended PCA rate, excluding class specific adjustments, to be 0.5655 ¢/kWh. As previously discussed, three customer groups have adjustments that make their PCA rates higher. Staff and Company agree on the dollar amounts of these adjustments but, once again, Staff proposes that the carry-over amounts be divided by a more appropriate level of energy consumption for the purpose of determining rates. The rate components associated with the carry-over deferral, interest and intervenor funding are calculated and shown on Attachment E, lines 13 through 16. Attachment F shows the PCA rates by class and component that are proposed by Staff and the rates proposed by the Company.

With regard to the calculation of PCA rates, there are only two differences between the Company and Staff recommendations. These comments have already discussed Staff's adjustments to the Company-proposed true up amounts. The other difference is in the energy (kWh) amounts used to determine the true up and class specific adder portions of the rates. The

Company used 1993 normalized energy and Staff used 2002 normalized energy.[15] The 2002 numbers are, on average, 10.4 % higher.

Normalized Energy (kWh)

Some discussion of PCA history is required to understand the justification for using one set of energy numbers as opposed to the other. For the first eight years of the PCA, 1993 through 2000, the computation of the true up rate was the true up dollar amount divided by normalized energy consumption. Normalized energy was established from time to time when the PCA base was updated. Generally, the base numbers were updated in a general rate case. The Company's last general rate case established normalized energy, Case No. IPC-E-94-5, based on a 1993 test year. Staff recognized from the beginning of the PCA that the Company's energy sales to customers normally grow annually and that rates established using out-dated base energy consumption would be higher than rates established using current energy consumption. Staff understood that establishing a rate using outdated energy consumption would over-recover true up surcharges and over-refund true up rebates as the rate is applied to higher, current annual energy consumption. In 1993 when PCA methodology was initially determined, use of normalized energy consumption as established in the Company's last general rate case was a simplification thought to be acceptable because true up surcharges and rebates were expected to be balanced and, in case they were not exactly balanced, true up amounts were expected to be relatively small resulting in small errors. Staff also expected that the base would be updated more regularly.

In PCA years nine and ten, 2001 and 2002, true up amounts were many times greater than the amounts previously experienced and the 1993 base energy consumption was very stale. In its PCA filings the Company departed from approved methodology and used updated normalized annual energy amounts to determine the true up rate. In both cases, Staff recognized the benefit to customers in terms of reduced PCA rates that more accurately recovered the very large true up amounts so Staff accepted use of the updated energy numbers. The Commission also accepted the use of updated energy in the true up rate calculation. Staff further recognized that if updated normalized energy had not been used to calculate the true up rate, the rate would have been

[15] The normalized energy used by the Company and by Staff is based on normal expected firm sales to Idaho customers during a specified time period.

higher and the true up amount would have been grossly over-collected by the Company. Staff estimates the over-collection for those two years would have been approximately $70 million. Since recovery of the true up is not tracked and trued up, the over-collection would have been the Company's to keep. Staff anticipates this over-collection will also occur in this PCA period if normalized annual energy is not updated.

In its filing this year the Company proposes to return to the use of 1993 normalized base energy amounts to determine the true up rate. This may have been appropriate if the true up amounts had returned to pre-2000 levels and the recovery assumptions and associated risks remained acceptable. However, that has not happened. As shown on Attachment G, this year's true up amount is the third largest ever. It is more than twice as much as any of the true up amounts prior to 2001. Also, its major components are the Astaris Voluntary Load Reduction (VLR) Contract and settlement costs which account for more than $29 million dollars or 75 % of this year's true up amount. Although spot market prices have returned to a range near normal, the Astaris VLR contract paid Astaris 15¢/kWh to not use a specified amount of energy through March 2003. This is much higher than the 3 to 4 ¢/kWh that one would expect to pay for energy under the normal market conditions that persisted through the true up year. This year's true up costs remain abnormally high. The majority of those high costs were contractually incurred during the period of extremely high market prices that existed in early 2001 when the Astaris VLR contract was signed. These are the same kind of very high costs recovered through the PCA during the last two years when the Company appropriately used updated energy amounts.

In addition to extraordinary true up cost levels, Staff proposes that the Commission use updated normalized energy for the purpose of calculating true up and carry-over rates for several other reasons. First, use of the most current normalized energy loads available provides the best estimate of actual customer use in the true up recovery period and thus the best chance of accurately recovering the true up amount. If the Company sells the expected amount of energy at a rate based on that same amount of energy, it will recover the revenue it is entitled to. A second reason for updating normalized customer energy loads is that some of the assumptions that made the use of outdated base load energy numbers acceptable are no longer true. Over-recovery of true up surcharges and rebates has not been symmetrical. There is no realistic scenario where good water conditions create unusual amounts of energy for the Company to sell at market when market prices are 10 or 20 times normal levels. When water conditions are really good, market prices generally fall not rise. It is also clear that true up amounts are neither offsetting nor small. In short, the true up amounts remain too large, offsetting rebates are not expected, and rates based on 1993 normalized energy will give the Company an unwarranted windfall at the expense of ratepayers.

If true up rates and carry-over rates are designed to recover the amounts proposed by Staff using 1993 energy (kWh), and 2002 energy amounts are actually sold, the true up component of the rate will recover approximately $42.1 million instead of the desired $38.1 million and the carry-over rate component will recover $16.5 million instead of the desired $16.0 million. Neither of these amounts are trued up so the Company will receive a $4.5 million windfall. This would not recover any costs incurred by the Company, it is simply an over-collection. If the Company files a rate case this year, the base will be updated and will more accurately reflect actual consumption in subsequent PCAs.

Cost Recovery

Attachment H shows rate reductions from current rates under Staff's proposal. As would be expected with a smaller true up amount and more energy to spread the above normal power supply costs over, Staff's proposal decreases rates more than the Company's proposal. The overall reduction proposed by Staff is 19.12%. This reduction amounts to $5.1 million more than Company-proposed rates would produce if 2002 amounts of energy are sold. The additional $5.1 million reduction is composed of a $0.6 million reduction in the underlying true up amount, and a $4.5 million reduction in true up and carry-over recovery associated with the use of updated energy amounts.

Attachment I shows how much above base rates (current or normal rates with no PCA adder) rates will be if the Commission accepts Staff's proposal. It also indicates that although a significant reduction is proposed in this filing, another substantial reduction is required to return rates to normal levels. Under Staff's proposal average rates will still be 17.41% above normal.

CONSUMER ISSUES ANALYSIS

Idaho Power's PCA Application filed on April 15, 2003 contained both the customer notice and press release. Customers were notified of the Application by bill stuffer and will have until May 8, 2003 to file comments with the Commission. Staff reviewed the customer notice and press release and determined both complied with the notice requirements of IDAPA 31.21.02.102.

The customer notice is being mailed with cyclical billings, resulting in a small percentage of customers not receiving the notice before the proposed decrease would become effective. However, Staff did not want to delay implementation of the decrease and determined that the 21-day period of time was sufficient for the Commission to receive customer comments.

As of May 7, 2003, the Commission had received six comments from customers. All of the customers supported the proposed decrease in rates. However, one commented Idaho Power should decrease rates more than 18.9% and another comment favored a larger decrease for small commercial users.

Between May 16, 2002, the effective date of the Company's previous PCA, and May 7, 2003, the Idaho Public Utilities Commission Consumer Assistance Staff received 492 complaints and inquiries regarding credit and collection issues. Of that number, 449 were concerning disconnection of service. This was an increase over the corresponding 2001-2002 time period when Staff received 429 complaints and inquires regarding credit and collection issues, of which 401 concerned disconnections. There was a significant decrease during the same time period in the number of complaints related specifically to Idaho Power's rates. Since the effective date of the last PCA, there have been 21 complaints regarding prices and rates. During the same time period the previous year there were 191 complaints, most of which were related to the tiered residential rates then in effect.

Although rates will decrease as a result of the proposal, rates remain higher than normal and there will always be customers who are unable to pay their bills in full each month. Based on Staff's review of complaints and inquiries, it appears that customers continue to struggle financially due to a lackluster economy and job layoffs. Therefore, Staff recommends that the Company encourage customer service representatives to continue to work with customers to establish payment arrangements when customers call the utility stating they are unable to pay bills in full. Staff also recommends Idaho Power continue to provide customers with energy conservation information.

RECOMMENDATIONS SUMMARY

Based on its analysis and review, Staff submits the following recommendations:

1. The purchased power transactions be approved with the changes noted by Staff.
2. The payments to and from Astaris be included in the PCA surcharge as booked.

3. That Idaho Power initiate an RFP process to manage its natural gas transportation before the expiration of the current IGI contract.
4. That customers should not be responsible for the $428,625 in proposed transmission expenses that Idaho Power would have to pay to IE.
5. The proposed IE settlement be flowed through to customers without any Company sharing.
6. That Idaho Power be required to continue to book monthly the $2 million annual benefit to customers the Company agreed to in the IPC-E-00-13 case stipulation.
7. That the mobile home metering costs and the intervenor funding be flowed through as recommended by the Company.
8. That the RMC be required to provide more information and documentation regarding the authorized transactions that are not carried out.
9. That true up rates and carry-over adder rates (including intervenor funding) be calculated using 2002 normalized Idaho jurisdictional firm load (energy) at the customer level.

Respectfully submitted this 8th day of May 2003.

Lisa D. Nordstrom

Lisa D. Nordstrom
Deputy Attorney General

Technical Staff: Keith Hessing
Alden Holm
Marilyn Parker

LN:i:/umisc/comments/ipce03.5lnkhah

2003/2004 FERC SETTLEMENT PCA ADJUSTMENT
Staff Adjusted Proposal

CONTRACT	DATE	AMOUNTS BOOKED TO ACCT #447	FERC SETTLEMENT MW	RATE	$	TRANSMISSION ADJUSTMENT	NET SETTLEMENT	ADJUSTMENT TO ACCT #447
Tri-State Reserves	Nov-01	19,584.00	9,600	8.25	79,200.00		79,200.00	
	Dec-01	22,766.40	11,160	8.25	92,070.00		92,070.00	
	Jan-02	24,031.20	11,780	8.25	97,185.00		97,185.00	
	Feb-02	21,705.60	10,640	8.25	87,780.00		87,780.00	
	Mar-02	24,031.20	11,780	8.25	97,185.00		97,185.00	
	Apr-02	23,256.00	11,400	8.25	94,050.00		94,050.00	
	May-02	45,532.80	22,320	8.25	184,140.00		184,140.00	
	Jun-02	44,064.00	21,600	8.25	178,200.00		178,200.00	
	Jul-02	45,532.80	22,320	12.00	267,840.00		267,840.00	
	Aug-02	45,532.80	22,320	8.25	184,140.00		184,140.00	
	TOTALS	**316,036.80**	**154,920**		**1,361,790.00**	**-**	**1,361,790.00**	**1,045,753.20**
Truckee Donner	**Aug-02**	**5,729.55**	**1.7**	**6.53 KW/MO**	**5,729.55**	**-**	**5,729.55**	**-**
Montana Power	Jun-01	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Jul-01	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Aug-01	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Sep-01	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Oct-01	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Nov-01	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Dec-01	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Jan-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Feb-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Mar-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Apr-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	May-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Jun-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Jul-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Aug-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Sep-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Oct-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Nov-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	Dec-02	195,900.00	30	8.25 KW/MO	247,500.00		247,500.00	
	TOTALS	**3,722,100.00**			**4,702,500.00**	**-**	**4,702,500.00**	**980,400.00**
Total Ancillary Services							**$ 6,070,019.55**	**$ 2,026,153.20**
Montana Power Energy							**$ 184,791.47**	**$ 184,791.47**
Total Compensation from IE to IPC							**$ 6,254,811.02**	**$ 2,210,944.67**
Idaho Jurisdiction (85%) - Staff's Recommendation to be Returned to Customers								**$ 1,879,302.97**
Idaho Power's Proposed Amount to be Returned to Customers								**$ 1,363,474.55**
Difference Between Idaho Power and Staff Recommendations								**$ 515,828.42**

Attachment A
Case No. IPC-E-03-5
Staff Comments
05/08/03

2002 - 2003 TRUE-UP CALCULATIONS
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-03-5
Staff Case

1	Jurisdictional Allocation Factor	85.0%							
2	Sharing Percentage	90.0%							
3	DESCRIPTION	Units	2002 APR	2002 MAY	2002 JUN	2002 JUL	2002 AUG	2002 SEPT	2002 OCT
4	**PCA Revenue**								
5	Normalized Firm Load	MWh	991,176	1,033,117	1,143,545	1,352,219	1,422,263	1,206,799	1,112,398
6	PCA Component Rate	m/KWh	3.861	2.981	2.156	2.156	2.156	2.156	2.156
7	Revenue Allocated at 85.0%	$	3,252,890.96	2,617,763.51	2,095,660.57	2,478,076.54	2,606,439.17	2,211,579.85	2,038,580.57
8	**Load Change Adjustment**								
9	Actual Firm Load	MWh	1,070,745	1,312,833	1,523,116	1,753,615	1,540,338	1,270,806	1,176,173
10	Normalized Firm Load	MWh	991,176	1,033,117	1,143,545	1,352,219	1,422,263	1,206,799	1,112,398
11	Load Change	MWh	79,569	279,716	379,571	401,396	118,075	64,007	63,775
12	Expense Adjustment (@16.84)	$	(1,339,941.96)	(4,710,417.44)	(6,391,975.64)	(6,759,508.64)	(1,988,383.00)	(1,077,877.88)	(1,073,971.00)
13	**Non-QF PCA**								
14	ACTUAL:								
15	Purchased Water	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	Irrigation Load Reduction	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	Astaris VLR	$	2,940,861.60	2,593,397.00	2,300,935.00	4,799,027.00	5,771,124.00	4,899,256.00	3,549,877.00
18	Mobile Generation	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	Master Metering Costs	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Fuel Expense - Coal	$	6,725,116.70	7,825,869.83	6,212,816.58	8,644,471.42	8,073,558.62	8,029,564.90	9,007,563.74
21	Fuel Expense - Gas	$	259,177.12	248,000.00	435,782.72	533,339.93	771,181.02	199,906.31	383,923.17
22	Non-Firm Purchases	$	2,834,699.15	3,485,355.76	4,512,167.40	11,269,932.37	5,524,912.67	1,207,162.08	1,296,507.38
23	Quantified Purchase from BPA	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	Surplus Sales	$	(5,400,359.79)	(1,657,392.27)	(433,783.47)	(744,348.59)	(1,942,255.40)	(3,351,220.63)	(3,784,231.55)
25	FMC Second Block Rev.	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	Expense Adjustment (@16.84)	$	(1,339,941.96)	(4,710,417.44)	(6,391,975.64)	(6,759,508.64)	(1,988,383.00)	(1,077,877.88)	(1,073,971.00)
27	Sub-Total	$	6,019,552.82	7,784,812.88	6,635,942.59	17,742,913.49	16,210,137.91	9,906,790.78	9,379,668.74
28	BASE:								
29	Fuel Expense	$	3,341,000.00	2,293,000.00	2,843,000.00	5,076,000.00	6,445,000.00	5,587,000.00	6,026,000.00
30	Non-Firm Purchases	$	339,000.00	1,356,000.00	1,872,000.00	2,473,000.00	1,252,000.00	615,000.00	162,000.00
31	Surplus Sales	$	(3,195,000.00)	(597,000.00)	(208,000.00)	(142,000.00)	(595,000.00)	(1,570,000.00)	(3,022,000.00)
32	FMC Second Block Rev.	$	(826,062.77)	(979,683.11)	(693,150.51)	(600,808.00)	(745,141.45)	(664,245.01)	(742,239.84)
33	Sub-Total	$	(341,062.77)	2,072,316.89	3,813,849.49	6,806,192.00	6,356,858.55	3,967,754.99	2,423,760.16
34	Change From Base	$	6,360,615.59	5,712,495.99	2,822,093.10	10,936,721.49	9,853,279.36	5,939,035.79	6,955,908.58
35	Deferral (Shared and Allocated)	$	4,865,870.93	4,370,059.43	2,158,901.22	8,366,591.94	7,537,758.71	4,543,362.38	5,321,270.06
36	**QF Deferral**								
37	Actual (incl. Meridian Amort.)	$	2,946,032.83	4,189,351.71	5,847,754.67	6,337,507.29	5,967,284.40	4,930,364.97	3,359,512.15
38	Base	$	2,038,265.00	3,024,735.00	5,108,325.00	5,317,475.00	5,059,785.00	3,531,295.00	2,438,425.00
39	Change From Base	$	907,767.83	1,164,616.71	739,429.67	1,020,032.29	907,499.40	1,399,069.97	921,087.15
40	Quantified Benefit from BPA	$	0.00	0.00	0.00	(47.00)	0.00	0.00	0.00
41	Total Non-shared Deferral	$	907,767.83	1,164,616.71	739,429.67	1,019,985.29	907,499.40	1,399,069.97	921,087.15
42	Deferral (Allocated)	$	771,602.66	989,924.20	628,515.22	866,987.50	771,374.49	1,189,209.47	782,924.08
43	Astaris VLR Credit	$	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	Astaris Take-or-Pay Charge	$	0.00	0.00	0.00	0.00	0.00	500,000.00	0.00
45	Mobile Home Metering Costs	$	8,812.89	6,903.82	782.05	0.00	0.00	0.00	0.00
46	Intervenor Funding	$	0.00	0.00	0.00	0.00	25,000.00	0.00	0.00
47	Credit From IDACORP Energy	$	(166,666.67)	(166,666.67)	(166,666.67)	(166,666.67)	(166,666.67)	(166,666.67)	(166,666.67)
48	**Staff Adjustments**	**$**	**0.00**	**0.00**	**0.00**	**(38,435.49)**	**0.00**	**(48,370.32)**	**0.00**
49	**Total Deferral**	$	2,226,728.85	2,582,457.28	525,871.25	6,550,400.74	5,561,027.36	3,805,955.02	3,898,946.90
50	**Principal Balances**								
51	Beginning Balance	$	0.00	2,226,728.85	4,809,186.12	5,335,057.38	11,885,458.11	17,446,485.47	21,252,440.49
52	Amount Deferred	$	2,226,728.85	2,582,457.28	525,871.25	6,550,400.74	5,561,027.36	3,805,955.02	3,898,946.90
53	Ending Balance	$	2,226,728.85	4,809,186.12	5,335,057.38	11,885,458.11	17,446,485.47	21,252,440.49	25,151,387.38
54	**Interest Balances**								
55	Accrual thru Prior Month	$	0.00	(3,549.17)	(27,290.50)	(11,441.33)	6,947.97	46,452.40	104,943.73
56	Interest @4% per Year	$	0.00	7,422.43	16,030.62	17,783.52	39,618.19	58,154.95	70,841.47
57	Prior Month's Interest Adj.	$	(3,549.17)	(31,163.76)	(181.45)	605.78	(113.77)	336.38	(9,860.44)
58	Total Current Month Interest	$	(3,549.17)	(23,741.33)	15,849.17	18,389.30	39,504.42	58,491.33	60,981.03
59	Interest Accrued to Date	$	(3,549.17)	(27,290.50)	(11,441.33)	6,947.97	46,452.40	104,943.73	165,924.76
60	**Balance in All Accounts**	$	2,223,179.68	4,781,895.62	5,323,616.05	11,892,406.09	17,492,937.87	21,357,384.22	25,317,312.14

61 Note: Negative amounts indicate benefit to ratepayers

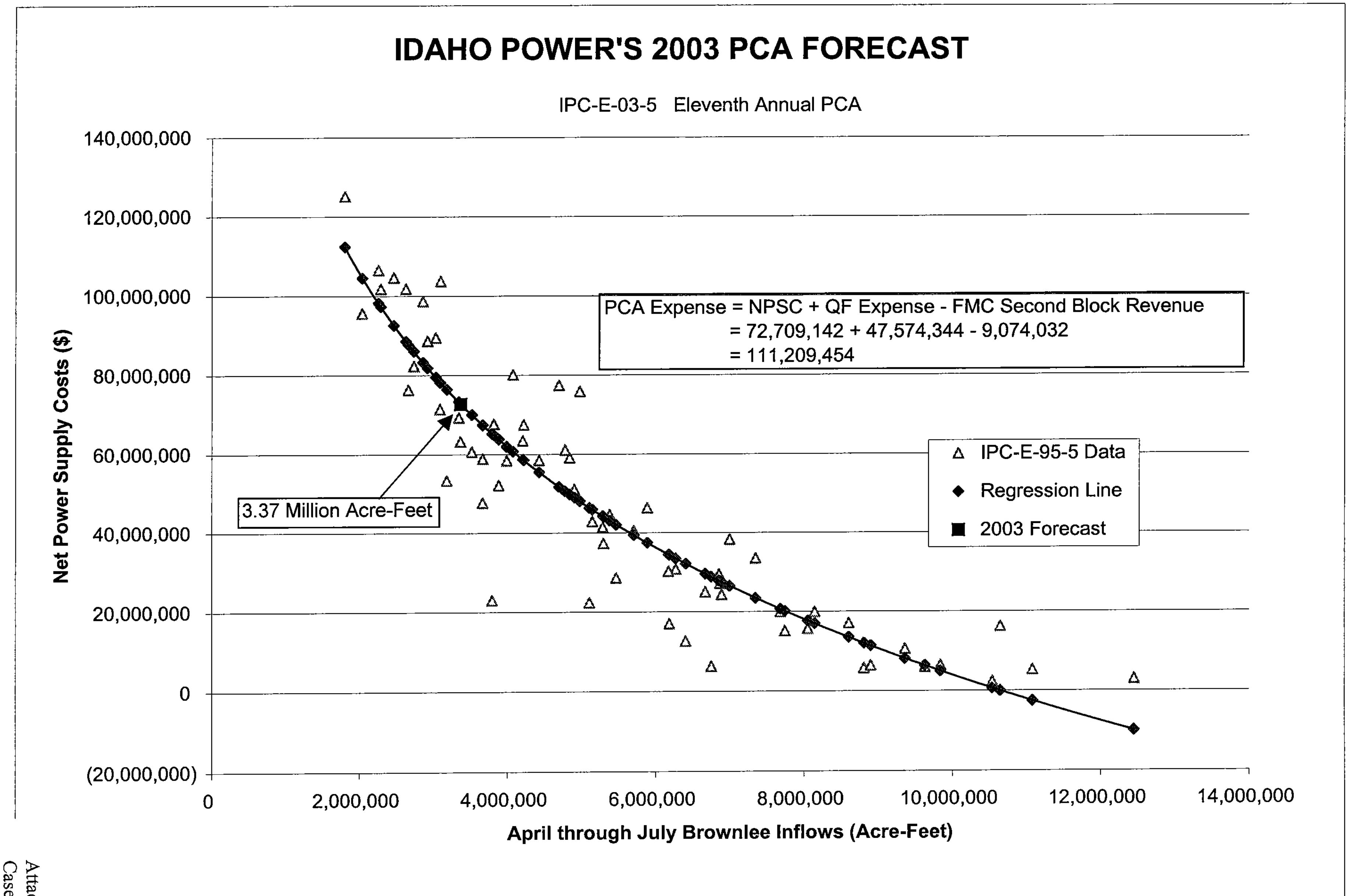
U:\khessln\ipce0305\staff case\TRUE-UP 5/6/2003 KDH

2002 - 2003 TRUE-UP CALCULATIONS
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-03-5
Staff Case

			2002	2002	2003	2003	2003	
1	Jurisdictional Allocation Factor	85.0%						
2	Sharing Percentage	90.0%						
3	DESCRIPTION	Units	NOV	DEC	JAN	FEB	MAR	TOTALS
4	**PCA Revenue**							
5	Normalized Firm Load	MWh	1,030,835	1,162,545	1,229,083	1,162,223	1,106,080	13,952,288
6	PCA Component Rate	m/KWh	2.156	2.156	2.156	2.156	2.156	
7	Revenue Allocated at 85.0%	$	1,889,108.22	2,130,479.97	2,252,417.51	2,129,889.87	2,027,002.21	27,729,895.94
8	**Load Change Adjustment**							
9	Actual Firm Load	MWh	1,180,382	1,298,897	1,281,353	1,129,269	1,128,293	15,665,829
10	Normalized Firm Load	MWh	1,030,835	1,162,545	1,229,083	1,162,223	1,106,080	13,952,293
11	Load Change	MWh	149,547	136,352	52,270	(32,954)	22,213	1,713,548
12	Expense Adjustment (@16.84)	$	(2,518,371.48)	(2,296,167.68)	(880,226.80)	554,945.36	(374,066.92)	(28,855,951.08)
13	**Non-QF PCA**							
14	ACTUAL:							
15	Purchased Water	$	0.00	0.00	0.00	0.00	0.00	15.00
16	Irrigation Load Reduction	$	0.00	0.00	0.00	0.00	0.00	16.00
17	Astaris VLR	$	3,407,962.00	3,501,610.00	3,090,697.00	38,826.00	0.00	36,893,589.60
18	Mobile Generation	$	0.00	0.00	0.00	0.00	0.00	18.00
19	Master Metering Costs	$	0.00	0.00	0.00	0.00	0.00	19.00
20	Fuel Expense - Coal	$	7,920,506.12	9,030,414.83	9,165,414.52	8,299,812.65	7,324,197.83	96,259,327.74
21	Fuel Expense - Gas	$	206,827.54	292,663.79	213,635.13	265,119.09	268,726.48	4,078,303.30
22	Non-Firm Purchases	$	2,947,948.08	8,012,846.19	2,366,083.10	(363,892.04)	2,905,178.94	45,998,923.08
23	Quantified Purchase from BPA	$	0.00	0.00	0.00	0.00	0.00	23.00
24	Surplus Sales	$	(1,286,388.10)	(5,130,598.28)	(2,554,140.40)	(5,624,596.67)	(7,692,419.85)	(39,601,711.00)
25	FMC Second Block Rev.	$	0.00	0.00	0.00	0.00	0.00	25.00
26	Expense Adjustment (@16.84)	$	(2,518,371.48)	(2,296,167.68)	(880,226.80)	554,945.36	(374,066.92)	(28,855,937.08)
27	Sub-Total	$	10,678,484.16	13,410,768.85	11,401,462.55	3,170,214.39	2,431,616.48	114,772,611.64
28	BASE:							
29	Fuel Expense	$	6,909,000.00	7,127,000.00	6,051,000.00	5,051,000.00	4,737,000.00	61,486,029.00
30	Non-Firm Purchases	$	345,000.00	844,000.00	879,000.00	642,000.00	296,000.00	11,075,030.00
31	Surplus Sales	$	(3,883,000.00)	(2,809,000.00)	(2,978,000.00)	(2,781,000.00)	(2,742,000.00)	(24,521,969.00)
32	FMC Second Block Rev.	$	(625,639.68)	(739,128.10)	(799,266.67)	(769,197.02)	(889,475.62)	(9,074,005.78)
33	Sub-Total	$	2,745,360.32	4,422,871.90	3,152,733.33	2,142,802.98	1,401,524.38	38,965,084.22
34	Change From Base	$	7,933,123.84	8,987,896.95	8,248,729.22	1,027,411.41	1,030,092.10	75,807,437.42
35	Deferral (Shared and Allocated)	$	6,068,839.74	6,875,741.17	6,310,277.85	785,969.73	788,020.46	57,992,689.63
36	**QF Deferral**							
37	Actual (incl. Meridian Amort.)	$	2,280,715.50	2,597,534.92	2,194,734.35	2,055,349.98	1,784,779.31	44,490,959.08
38	Base	$	1,539,895.00	1,713,885.00	1,567,845.00	1,459,785.00	1,314,445.00	34,114,198.00
39	Change From Base	$	740,820.50	883,649.92	626,889.35	595,564.98	470,334.31	10,376,801.08
40	Quantified Benefit from BPA	$	0.00	0.00	0.00	0.00	0.00	(7.00)
41	Total Non-shared Deferral	$	740,820.50	883,649.92	626,889.35	595,564.98	470,334.31	10,376,756.08
42	Deferral (Allocated)	$	629,697.43	751,102.43	532,855.95	506,230.23	399,784.16	8,820,249.82
43	Astaris VLR Credit	$	0.00	0.00	(419,727.00)	(5,273.00)	0.00	(424,957.00)
44	Astaris Take-or-Pay Charge	$	0.00	500,000.00	0.00	0.00	275,663.00	1,275,707.00
45	Mobile Home Metering Costs	$	0.00	0.00	0.00	0.00	0.00	16,543.76
46	Intervenor Funding	$	1,137.50	0.00	0.00	0.00	0.00	26,183.50
47	Credit From IDACORP Energy	$	(166,666.67)	(166,666.67)	(166,666.67)	(166,666.67)	(166,666.63)	(1,999,953.00)
48	**Staff Adjustments**	**$**	**0.00**	**0.00**	**0.00**	**0.00**	**(515,828.42)**	**(602,586.23)**
49	**Total Deferral**	$	4,643,899.77	5,829,696.96	4,004,322.63	(1,009,629.58)	(1,246,029.64)	37,373,696.52
50	**Principal Balances**							
51	Beginning Balance	$	25,151,387.38	29,795,287.15	35,624,984.12	39,629,306.74	38,619,677.16	
52	Amount Deferred	$	4,643,899.77	5,829,696.96	4,004,322.63	(1,009,629.58)	(1,246,029.64)	37,373,699.52
53	Ending Balance	$	29,795,287.15	35,624,984.12	39,629,306.74	38,619,677.16	37,373,647.52	
54	**Interest Balances**							
55	Accrual thru Prior Month	$	165,924.76	250,352.58	349,659.37	468,536.90	600,634.59	
56	Interest @4% per Year	$	83,837.96	99,317.62	118,749.95	132,097.69	128,732.26	772,642.66
57	Prior Month's Interest Adj.	$	589.86	(10.83)	127.58	0.00	(5.24)	(43,168.06)
58	Total Current Month Interest	$	84,427.82	99,306.79	118,877.53	132,097.69	128,727.02	729,474.60
59	Interest Accrued to Date	$	250,352.58	349,659.37	468,536.90	600,634.59	729,361.60	
60	**Balance in All Accounts**	$	30,045,639.73	35,974,643.49	40,097,843.64	39,220,311.75	38,103,009.13	38,103,009.13

61 Note: Negative amounts indicate benefit to ratepayers

U:\khessln\ipce0305\staff case\TRUE-UP 5/6/2003 KDH



Attachment C
Case No. IPC-E-03-5
Staff Comments
05/08/03

CARRY-OVER AMOUNTS, INTEREST AND INTERVENOR FUNDING

Line No.	Customer Group	Rate Schedule	Carry-Over ($)	Interest @ 6% ($)	Intervenor Funding ($)	Total ($)
1	Small General Service	7	577,033	34,622	0	611,655
2	Large Power Service	19	3,635,405	163,593	0	3,798,998
3	Irrigation Service	24 & 25	10,953,165	657,190	7,314	11,617,669

2003-2004 PCA - Eleventh Annual
IPC-E-03-5
Staff Case

Line	Description	Units	Base	Forecast	Difference	Rate
1	2003 - 2004 Forecast:					
2	PCA Expense	($)	73,079,128	111,209,454	38,130,326	
3	Normalized Energy - Total System	(MWH)	13,952,283	13,952,283		
4	Energy Rate	(¢/kWh)	0.52378	0.79707	0.27329	
5	Sharing Percentage	(%)			90%	
6	Energy Rate Difference	(¢/kWh)			0.24596185	0.2460
7			($)	(MWh)	($/MWh)	(¢/kWh)
8	2002-2003 True-up		38,103,009.13	11,926,360	3.19485653	0.3195
9	PCA Rates:					
10	Proposed PCA Rate Adj. from Base	(¢/kWh)				0.5655
11	PCA Rate Currently in Effect	(¢/kWh)				1.9370
12	Total Rate Difference	(¢/kWh)				(1.3715)
13	Carry-Over Adders and Intervenor Funding:					
14	Schedule 7 - Small General Service		611,655	267,241	2.288776797	0.2289
15	Schedule 19 - Large Power Service		3,798,998	1,928,629	1.969792013	0.1970
16	Schedule 24 - Irrigation & Pump		11,617,669	1,640,999	7.079632096	0.7080
17			Rate	Energy	Revenue	Total
18	Expected PCA Revenues:		($/MWh)	(MWh)	($)	Rate
19	Forecast Revenue		2.460	11,926,360	29,338,846	0.2460
20	True Up Revenue		3.195	11,926,360	38,104,720	0.3195
21	Schedule 7 - Small General Service		2.289	267,241	611,715	0.7944
22	Schedule 19 - Large Power Service		1.970	1,928,629	3,799,399	0.7625
23	Schedule 24 - Irrigation & Pump		7.080	1,640,999	11,618,273	1.2735
					83,472,952	
24	Note: Negative rates and amounts indicate benefits to ratepayers.					

Attachment E
Case No. IPC-E-03-5
Staff Comments
05/08/03

STAFF PROPOSED PCA RATES
IPC-E-03-5

Line No.	Tariff Description	Schedule No.	Forecast Rate (¢/kWh)	True Up Rate (¢/kWh)	Carry-Over Rate (¢/kWh)	Total PCA Rate (¢/kWh)
1	Uniform Tariff Rates:					
2	Residential Service	1	0.2460	0.3195	0.0000	0.5655
3	Small General Service	7	0.2460	0.3195	0.2289	0.7944
4	Large General Service	9	0.2460	0.3195	0.0000	0.5655
5	Dusk to Dawn Lighting	15	0.2460	0.3195	0.0000	0.5655
6	Large Power Service	19	0.2460	0.3195	0.1970	0.7625
7	Irrigation Service	24	0.2460	0.3195	0.7080	1.2735
8	Unmetered General Service	40	0.2460	0.3195	0.0000	0.5655
9	Municipal Street Lighting	41	0.2460	0.3195	0.0000	0.5655
10	Traffic Control Lighting	42	0.2460	0.3195	0.0000	0.5655
11	Special Contracts:					
12	Micron	26	0.2460	0.3195	0.0000	0.5655
13	FMC	28	0.2460	0.3195	0.0000	0.5655
14	J R Simplot	29	0.2460	0.3195	0.0000	0.5655
15	DOE	30	0.2460	0.3195	0.0000	0.5655

COMPANY PROPOSED PCA RATES

Line No.	Tariff Description	Schedule No.	Forecast Rate (¢/kWh)	True Up Rate (¢/kWh)	Carry-Over Rate (¢/kWh)	Total PCA Rate (¢/kWh)
16	Uniform Tariff Rates:					
17	Residential Service	1	0.2460	0.3583	0.0000	0.6043
18	Small General Service	7	0.2460	0.3583	0.2438	0.8481
19	Large General Service	9	0.2460	0.3583	0.0000	0.6043
20	Dusk to Dawn Lighting	15	0.2460	0.3583	0.0000	0.6043
21	Large Power Service	19	0.2460	0.3583	0.2178	0.8221
22	Irrigation Service	24	0.2460	0.3583	0.7120	1.3163
23	Unmetered General Service	40	0.2460	0.3583	0.0000	0.6043
24	Municipal Street Lighting	41	0.2460	0.3583	0.0000	0.6043
25	Traffic Control Lighting	42	0.2460	0.3583	0.0000	0.6043
26	Special Contracts:					
27	Micron	26	0.2460	0.3583	0.0000	0.6043
28	FMC	28	0.2460	0.3583	0.0000	0.6043
29	J R Simplot	29	0.2460	0.3583	0.0000	0.6043
30	DOE	30	0.2460	0.3583	0.0000	0.6043

HISTORIC PCA TRUE UP AMOUNTS

Staff Case
IPC-E-03-5
Summary of Revenue Impact
State of Idaho
Normalized 12-Months Ending December 31, 2002
5/16/02 PCA Rates to 5/16/03 PCA Rates

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Tariff Description	Rate Sch. No.	2002 Avg. Number of Customers	2002 Sales Normalized (kWh)	2002 Base w/ 7/1/02 PCA Revenue	Proposed PCA Revenue Adjustments	Proposed Total Revenue	Average ¢/kWh	Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1		4,100,268,216	291,000,376	(56,235,179)	234,765,198	5.726	-19.32%
2	Small General Service	7		267,241,060	21,493,752	(2,484,540)	19,009,212	7.113	-11.56%
3	Large General Service	9		2,949,525,621	162,983,658	(40,452,744)	122,530,914	4.154	-24.82%
4	Dusk to Dawn Lighting	15		5,819,680	1,495,362	(79,817)	1,415,545	24.323	-5.34%
5	Large Power Service	19		1,928,629,241	87,047,261	(18,545,699)	68,501,562	3.552	-21.31%
6	Irrigation Service	24		1,640,999,114	84,527,289	(1,115,879)	83,411,410	5.083	-1.32%
7	Unmetered General Service	40		16,253,157	1,266,900	(222,912)	1,043,988	6.423	-17.60%
8	Municipal Street Lighting	41		17,511,128	2,139,096	(240,165)	1,898,930	10.844	-11.23%
9	Traffic Control Lighting	42		9,092,233	458,505	(124,700)	333,805	3.671	-27.20%
10	Sub-Total			10,935,339,450	652,412,199	(119,501,635)	532,910,564	4.873	-18.32%
	Special Contracts:								
11	Micron	26		606,779,674	26,626,497	(8,321,983)	18,304,514	3.017	-31.25%
12	FMC	28		0	0	0	0	0.000	0.00%
13	J R Simplot	29		182,788,001	8,553,272	(2,506,937)	6,046,334	3.308	-29.31%
14	DOE	30		201,452,499	8,452,719	(2,762,921)	5,689,798	2.824	-32.69%
15	Sub-Total			991,020,174	43,632,488	(13,591,842)	30,040,646	3.031	-31.15%
16	Total Annual Idaho Retail Sales			11,926,359,624	696,044,686	(133,093,477)	562,951,210	4.720	-19.12%

U:\khessin\IPCE0305\Staff Case\Revenue Summary 5/2/2003 KDH

Staff Case
IPC-E-03-5
Summary of Revenue Impact
State of Idaho
Normalized 12-Months Ending December 31, 2002
5/16/99 Base Rates to 5/16/03 PCA Rates

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Tariff Description	Rate Sch. No.	2002 Avg. Number of Customers	2002 Sales Normalized (kWh)	Base Revenue	Proposed PCA Revenue Adjustments	Proposed Total Revenue	Average ¢/kWh	Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1		4,100,268,216	211,578,181	23,187,017	234,765,198	5.726	10.96%
2	Small General Service	7		267,241,060	16,886,249	2,122,963	19,009,212	7.113	12.57%
3	Large General Service	9		2,949,525,621	105,851,347	16,679,567	122,530,914	4.154	15.76%
4	Dusk to Dawn Lighting	15		5,819,680	1,382,635	32,910	1,415,545	24.323	2.38%
5	Large Power Service	19		1,928,629,241	53,795,764	14,705,798	68,501,562	3.552	27.34%
6	Irrigation Service	24		1,640,999,114	62,513,286	20,898,124	83,411,410	5.083	33.43%
7	Unmetered General Service	40		16,253,157	952,076	91,912	1,043,988	6.423	9.65%
8	Municipal Street Lighting	41		17,511,128	1,799,905	99,025	1,898,930	10.844	5.50%
9	Traffic Control Lighting	42		9,092,233	282,388	51,417	333,805	3.671	18.21%
10	Sub-Total			10,935,339,450	455,041,831	77,868,733	532,910,564	4.873	17.11%
	Special Contracts:								
11	Micron	26		606,779,674	14,873,175	3,431,339	18,304,514	3.017	23.07%
12	FMC	28		0	0	0	0	0.000	0.00%
13	J R Simplot	29		182,788,001	5,012,668	1,033,666	6,046,334	3.308	20.62%
14	DOE	30		201,452,499	4,550,584	1,139,214	5,689,798	2.824	25.03%
15	Sub-Total			991,020,174	24,436,427	5,604,219	30,040,646	3.031	22.93%
16	Total Annual Idaho Retail Sales			11,926,359,624	479,478,258	83,472,952	562,951,210	4.720	17.41%

U:\khessin\IPCE0305\Staff Case\Revenue Summary 5/2/2003 KDH

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 8TH DAY OF MAY 2003, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-03-05, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

BARTON L KLINE
MONICA MOEN
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070

GREGORY W SAID
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070

Mary Jo Nelson
SECRETARY