Office of the Secretary
Service Date
May 1, 2001

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE IDAHO POWER COMPANY APPLICATION FOR A REFUNDABLE EMERGENCY ENERGY CHARGE FOR THE RECOVERY OF EXTRAORDINARY POWER SUPPLY EXPENSES.	**CASE NO. IPC-E-01-7**
IN THE MATTER OF THE IDAHO POWER COMPANY APPLICATION FOR AUTHORITY TO IMPLEMENT A POWER COST ADJUSTMENT (PCA) RATE FOR ELECTRIC SERVICE FROM MAY 1, 2001 THROUGH MAY 15, 2002.	**CASE NO. IPC-E-01-11** **NOTICE OF PREHEARING CONFERENCE** **ORDER NO. 28722**

SUMMARY OF COMMISSION ORDER

In February and March 2001, Idaho Power Company filed two Applications seeking to increase its rates under the annual Power Cost Adjustment (PCA) mechanism first approved by the Commission in 1993. Idaho Power supplies electricity to approximately 360,000 customers across southern Idaho. In its February Application, the Company sought to recover $161 million that represented the amount of off-system power purchases over the preceding 10 months. In March 2001, the Company filed its second Application requesting authority to recover approximately $66.4 million in revenues. Thus, the Company requested recovery of a total of $227.4 million by imposing a uniform 1.8889¢ per kilowatt hour charge for all its customers over a one year period. The proposed rate change reflected an average 45.6% increase above current rates.

In this Order, the Commission finds that Idaho Power should be allowed to immediately recover approximately $168.3 million through the PCA mechanism. This represents 74% of the Company's request and is $159.6 million above current rates. The Commission has deferred recovery of approximately $59 million pending further investigation of several issues. Furthermore, the Commission determined that it is appropriate to initiate an investigation regarding several of the trading practices used to purchase power for the regulated company; whether the purchasing entity failed to execute a timely purchase of power when requested to do so; whether the Company appropriately hedged against market volatility; whether the pricing mechanism used to purchase power should be amended on a prospective basis; and whether the Company's resource plans are adequate to prospectively address current drought and market conditions. The Commission intends to proceed expeditiously in its review of the deferred issues.

After reviewing the record in this matter, the Commission has determined that the rates for the non-residential customer classes should be uniformly increased by 1.3415¢ per kWh over base rates. The percentage increase for each customer class over current rates is: irrigation – 31.3%; small commercial – 18.8%; large commercial – 32.9%; and industrial – 42.1%. The Commission has determined that the approved rates for residential customers should be spread over three blocks that increase as a customer's electric consumption increases. The overall average rate increase for residential customers is 23%. This translates into residential increases of 14.4% for the first block (monthly usage of up to 800 kWs), 28.8% for the second block (monthly usage between 801 and 2000 kWs), and 62% for the third block (monthly usage over 2001 kWs). The average residential customer using 1200 kWh per month would experience a monthly increase from $62.72 to $74.29, or an increase of 18.4%. This rate design is specifically intended to provide rate incentives for customers to conserve electricity.

Finally, in response to comments filed by the parties and members of the public, the Commission has directed Idaho Power to submit additional energy conservation proposals designed to provide customers with the opportunity to reduce electric consumption.

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I. BACKGROUND

A. History of PCA

Because Idaho Power Company is an electric utility that relies predominantly upon hydroelectric generation, the Company's actual costs of providing electricity (i.e., its power supply costs) can vary dramatically from year to year depending upon changes in streamflow and market prices. When streamflows or snowpacks are low, Idaho Power must rely increasingly upon off system purchases and its other generating resources and/or market purchases that are more costly than hydro generation. Conversely, in years of abundant streamflows with correspondingly plentiful, inexpensive hydro generation, the Company's power supply costs are lower. To ameliorate the adverse consequences of fluctuating power supply costs both to customers and the Company, the Commission instituted a "power cost adjustment" (PCA) mechanism in 1993.

The PCA is comprised of two major components. First, the Company is allowed to recover its above normal power supply costs[1] for the preceding 12 months including off-system purchases used to serve Idaho system load.[2] Second, rates are adjusted on an annual basis to

[1] The term "power supply costs" means additional purchases and fuel costs plus decreased surplus sales revenue.

[2] The term "Idaho system load" means that amount of electricity necessary to serve Idaho ratepayers. For the purpose of this Order, it is synonymous with "system operations" as discussed in the section on trading practices.

compensate for the succeeding 12 months' power supply costs based on expected Snake River streamflows and storage. Order No. 24806 at 2-3. For example, for projected periods of low water the Company receives revenues to generate or purchase the necessary replacement power. For periods of high water, customers experience credits from the sale of surplus power. Thus, under the PCA mechanism ratepayers receive a credit when power costs are low and receive a surcharge when power costs are high.[3] During the seven years that the PCA has been in effect, there have been three annual credits and four annual surcharges. This PCA case is the largest amount ever requested – nearly 6 times larger than the next largest increase.[4]

Idaho Power rates are adjusted each May after the Company files its PCA application. The PCA rate usually extends from May 16 to May 15 of the following year. Procedurally, PCA cases are normally processed on an expedited basis through the submission of written comments. IDAPA 31.01.01.122.02.

B. The Two Applications

On February 23, 2001, Idaho Power Company filed an Application in Case No. IPC-E-01-7 for authority to implement a flat "emergency energy charge" of 1.2737¢ per kilowatt-hour (kWh) applicable to all customer classes for a 12-month period. The Company sought to recover an unprecedented $161 million in additional power supply costs incurred over the prior 10 months.

On March 20, 2001, Idaho Power Company filed an additional Application in Case No. IPC-E-01-11 for authority to increase the PCA rate schedule from the existing 0.1371¢ per kWh rate to 0.6152¢ per kWh. The proposed rate increase in this second case is primarily based upon forecasted[5] below-average water flows in Idaho's hydroelectric system for the coming year. If approved, this Application alone would result in an overall revenue increase of approximately $66.4 million.

If approved, these two Applications (hereinafter referred to as the "combined PCA filing") would recover approximately $227.4 million through a flat 1.8889¢ per kWh charge

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

[4] The next largest increase was $38 million.

[5] Typically this forecast is based upon an April 1 projection of April through July runoff at Brownlee Reservoir. Because the Commission requested that Idaho Power file its PCA case early, the Company substituted a March 1 projection of the April through July Brownlee runoff.

imposed on the Company's customers for one year. Because not all customers pay the same per-kilowatt-hour charge, the proposed 1.8889¢ per kWh charge represents a different percentage increase for each customer class. Idaho Power's proposed approximate rate increases for major customer groups are set out below:

CUSTOMER GROUP	TODAY'S AVERAGE RATE	PROPOSED AVERAGE RATE	PERCENTAGE INCREASE
Residential	5.2 cents per kWh	7.1 cents per kWh	34.4%
Irrigation	3.9 cents per kWh	5.8 cents per kWh	46.8%
Small Commercial	6.4 cents per kWh	8.3 cents per kWh	27.9%
Large Commercial	3.7 cents per kWh	5.5 cents per kWh	49.6%
Industrial	2.9 cents per kWh	4.7 cents per kWh	62.8%

Source: Order No. 28685 at 3.

The combined proposed rate change reflects an average 45.6% increase to current Idaho Power rates. More specifically, the Company's bill stuffer notifies customers that a typical monthly residential bill for 1200 kWh will increase from $62.72 to $84.34 if the proposed 1.8889¢ rate increase were approved.

C. Proceedings

Although the Company requested in its IPC-E-01-7 filing that the emergency energy charge become effective on March 26, 2001, the Commission suspended the effective date until May 1, 2001. Order No. 28665. The suspension allowed the Commission time to examine the prudency of the Company's power purchases, review the Company's promotion of its conservation policies, and conduct public workshops and hearings. When it later filed its PCA Application in IPC-E-07-11, the Company requested an effective date of May 1, 2001 to enable both Applications to be decided in this joint Order. Because the Commission normally considers both PCA elements together, the Commission issued Order No. 28665 to combine the proposed emergency energy charge (IPC-E-01-7) and the PCA (IPC-E-01-11) into a single proceeding. This has facilitated comprehensive consideration of all components of the PCA.

To gather public input on the combined PCA filing, the Commission held workshops and public hearings in American Falls, Pocatello, Twin Falls, Caldwell and Boise. Approximately 105 people attended the five workshops and 118 people observed the four hearings.[6] Of those who attended, 41 people testified at the hearings.

[6] Although no public hearing was held in American Falls, those who attended the American Falls workshop could testify the following evening at the Pocatello hearing.

In Order Nos. 28665 and 28685, the Commission solicited written comments to be filed on or before April 16, 2001. As of that date the Commission received 314 individual written comments from the public and 23 petitions containing a total of 406 signatures. All but 10 of the public comments received objected to the proposed PCA increase.

D. Parties

The following persons were made parties to the combined PCA filing.

Idaho Power Company	Larry D. Ripley
Commission Staff	Lisa Nordstrom Deputy Attorney General
Astaris LLC	Conley Ward Givens Pursley LLP
	Ken Tandy Astaris LLC
Irrigation Pumpers Association, Inc.	Randall C. Budge Racine Olson Nye Budge & Bailey, Chartered
	Anthony Yankel
U.S. Department of Energy	Lawrence A. Gollomp Assistant General Counsel
Land & Water Fund of the Rockies Mary McGown	William M. Eddie
Idaho Rivers United	Sara C. Denniston
Idaho Rural Council	Kristy Webb
Industrial Customers of Idaho Power	Peter J. Richardson Molly O'leary Richardson & O'leary
	Stuart Trippel Trippel Mast Consulting

Each party filed written comments except Astaris, which provided oral testimony at the Pocatello hearing. Staff and the Company participated in all of the public hearings. Idaho

Power Company filed its response to these comments on April 21, 2001. With this background, we turn to the issues.

II. THE WATER FORECAST COMPONENT

As explained above, the forecasted water conditions for the next 12 months are the second component of the PCA. In their comments, the Company and the Staff agreed that expected power supply costs totaled $132,938,867, based on forecasted April through July 2001 Brownlee inflows. After computing the above-normal power supply costs, the Company determined that the PCA rate should recover $41.7 million when adjusted for Idaho's jurisdictional share of the increase and the 90/10 sharing between ratepayers and shareholders. The Staff calculated the power supply costs attributable to low streamflow as $45.8 million but its calculation was based upon a different amount of assumed kWh expected to be sold by Idaho Power. However, the Staff and the Company agreed that a rate of .3861¢ per kWh was necessary to recover anticipated power supply costs.

Although the Company sought to impose the .3861¢ per kWh as part of the PCA rate, Staff recommended this forecasted amount be deferred until next year's PCA. Staff asserts the forecast amount severely underestimates expected power supply costs in light of low reservoir water and high market prices. In its response, the Company does not believe deferring this amount until next year's PCA is in the public interest. Response at 5. The Company maintained that deferring the water forecast amount from this year's PCA

> will only exacerbate the Company's true-up for next year and will provide no cash to pay for the increased power supply costs we all know are coming. Additionally, those who set the Company's credit ratings and those who provide it with much needed capital in these difficult times are also watching this decision very closely. Failure to include the [water] forecast in the PCA adjustment will likely be viewed as failure of the mechanism to assure recovery of costs resulting in credit downgrades and restricted access to capital in the marketplace when it is needed most.

Id.

Commission Findings. Based upon our review of the record, the Commission finds that the PCA rate attributable to predicted streamflows is .3861¢ per kWh. See Appendix 1 to this Order.

Although the Commission understands that Staff's purpose in recommending deferred recovery of this PCA component is to mitigate the anticipated large rate increase this year, deferring this amount would only increase next year's PCA rate. Staff's reasoning that the low water projection will underestimate actual power supply costs is in itself justification for allowing recovery in this PCA case. The Commission is hopeful that regional power market prices will decline and that Idaho will soon experience an above-average water year. Even if these favorable conditions come to pass, the Commission is concerned that next year's PCA request may be sizable to recover excess power purchase costs incurred during the coming year and to fund conservation or demand-side management programs like the Irrigation Buy-Back Program.

The Commission finds it reasonable and in the public interest to allow recovery of the forecasted power supply costs in the current 2000-2001 PCA. The PCA was designed to allow consistent recovery of anticipated power supply costs. The Commission chooses not to deviate from the established formula in this case. Given the volatility and high wholesale prices in regional power markets, the Commission finds immediate recovery of the forecast amount is reasonable. This recovery also assures the financial community that the Company will be allowed to recover its reasonably incurred power supply costs. Moreover, immediate recovery of this forecasted amount will minimize the interest costs that would otherwise be included in next year's PCA.

III. THE POWER SUPPLY COSTS COMPONENT

Of the total $227.4 million PCA revenue requested by the Company, approximately $186 million is attributable to last year's unrecovered power supply costs. Idaho Power applied for $161 million in its emergency energy charge filing in IPC-E-01-7 for 90% of above forecasted power supply costs from April 2000 through January 2001.[7] In its PCA filing in IPC-E-01-11, the Company requested an additional $25 million to recover the customer's share of forecasted power supply costs for February 2001. To facilitate the early PCA filing requested by the Commission, recovery of the customers' portion of the March 2001 above forecast power supply costs will be deferred to the 2001-2002 PCA case.

[7] See *infra* note 3.

Staff recommended recovery of $126.212 million of the $186 million in power supply costs. Staff indicated that these costs were reasonably and prudently incurred to serve the Company's Idaho customers. Staff also recommended that $8 million be recorded below-the-line, thus denied recovery, and that recovery of the remaining $51 million be deferred pending further investigation. See Trading Practices and Disputed November Transaction Sections below. Other parties also recommended that portions of the PCA be denied for various reasons. The Rural Council suggested that one-third of the total PCA request be denied. Rural Council Comments at 3. The Industrial Customers of Idaho Power (ICIP) and others argue that some of the power purchases may have been imprudent and any rate increase should be subject to refund. ICIP Comments at 20. Parties also urged the Commission to initiate a general rate case or initiate an investigation into issues in this case. *Id.* at 5-6, 18-19; Irrigation Pumpers Comments at 2; Land and Water Fund and Idaho Rivers United Comments at 3; DOE Comments at 3.

Commission Findings. The Commission finds that $126.212 million excess power supply costs should be recovered immediately in this PCA. Although some parties offered general objections or concerns about the purchase power component, the Commission is persuaded by the Staff comments. As discussed below in greater detail, the Commission shall defer recovery of some power supply costs and open an investigation to examine some of the issues raised by the parties. However, it is evident that the Company did purchase power to meet its obligation to serve Idaho ratepayers.

1. Adjustments. Staff concurred with two adjustments made by the Company in its "true-up" calculation. First, the Company adjusted the load change expense for February 2001 to account for differences in "actual firm load" reported in previous months. Second, the Company adjusted the interest calculation on the deferred balance of August, October and February to reflect differences in market purchases, sales, and load change expenses reported in previous months.

The Company used a 5% interest rate for April through December 2000 and a 6% interest rate for January and February 2001 in its calculation. To be consistent with past PCA calculations, Staff recommended that the 5% interest rate be used for the entire PCA period. Staff Comments at 5. By previous agreement between the Company and Staff, a single Commission-approved interest rate (i.e., the rate paid on customer deposits effective at the beginning of the PCA year) has previously been used for all months in the PCA year.[8] IDAPA 31.21.01.106.

Commission Findings. The Commission finds that the adjustments agreed to by the Company and the Staff are reasonable and should be adopted. To maintain consistency with prior PCA cases, the Commission further finds it appropriate to apply the 5% interest rate on deposits to the deferred balances for the entire PCA period of April 2000 through March 2001.

2. Consumption Data. Staff pointed out in its comments that the Company used different annual energy consumption totals to calculate the PCA rates proposed in its two separate filings. In the emergency surcharge case (IPC-E-01-7), the Company used normalized 1999 Idaho jurisdictional firm load of 12,632,017 MWh.[9] In its second filing (IPC-E-01-11), the Company used 10,802,636 MWh – the normalized Idaho jurisdictional firm load that was used in the Company's last general rate case. Staff recommended that the Commission use the 1999 Idaho jurisdictional load of 12,770,405 MWh.[10] Staff Comments at 39.

Commission Findings. The Commission finds it appropriate to adopt the Staff and Company proposal to use normalized 1999 kWh for 12 and one-half months (13,253,976 MWh) to calculate this year's true-up PCA rate. If the Company sells this amount of electricity, as it expects to, the Company will recover all of its true-up costs. See Appendix 2.

A. Trading Practices

1. Background. The Commission received many comments regarding the relationship and the transactions that have occurred between the regulated entity (Idaho Power Company) and another subsidiary called IDACORP Energy Solutions (IES). Idaho Power and IES are both wholly-owned subsidiaries of IDACORP, Inc. IDACORP desired that IES engage in the marketing of electricity and natural gas on the wholesale level. In other words, IES will "trade" (actually purchasing and selling) natural gas and electricity as commodities.

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[8] This practice was instituted to simplify the true-up calculation and adopts the interest rate established by the Commission at the beginning of each calendar year.

[9] The Company has subsequently indicated that the correct normalized 1999 Idaho jurisdictional firm load is 12,770,405 MWh.

[10] The Company's response proposed to add 483,571 MWh to the 12,770,405 MWh load amount, for a total of 13,253,976. This additional amount is the one-half of May's kWh that must be recovered to effectuate a May 1, 2001 effective date.

a. <u>The IES Agreement</u>. On September 1, 2000, Idaho Power filed an Application requesting that the Commission approve a proposed Electric Supply and Management Services Agreement (Agreement) between Idaho Power and IES. This Agreement was reached after approximately two years of negotiation, after which Staff recommended approval of the Agreement. Under the Agreement, Idaho Power sought authority to transfer its operating transactions (e.g., purchasing and selling power for itself to meet the utility's Idaho system load) to IES. Agreement ¶ 1, Atch. 1 ¶ 3.1. Such transactions or trades for Idaho Power are referred to as "operating or system transactions." IES would also engage in transactions in the wholesale power market that do not involve sales from Idaho Power resources and are not related to the Idaho Power system. For example, IES would purchase gas and electricity from third parties and resell these commodities to parties other than Idaho Power. Such electric transactions are referred to as "non-operating or non-system transactions."

The Attachment to the Agreement noted that the "sales price for delivered energy and capacity acquired by Idaho Power from IES to supply Native Load will be equal to the Market Price determined in accordance with Section 5." Agreement, Atch. 1, ¶ 3.1, the market price for purchasing power to meet Idaho Power's obligation to serve its Idaho system load was based on the Dow Jones Mid-Columbia Electricity Price Index (Mid-C). *Id.* at ¶ 5.1.

In addition to the pricing mechanism, Idaho Power would compensate IES for its services in the amount of $300,696.30 per month. *Id.*, ¶ 6.1. In addition to purchasing and trading for Idaho Power, IES proposed to provide other management services such as executing "hedges" intended to "minimize the risk of financial loss from an adverse price change in a commodity market." Atch. 1, ¶ 2.1.3. Other services include real-time power marketing, intramonth power marketing (trades that supply power from one day to one month), and risk management activities intended to reduce risk of losses "that would cause Idaho Power to incur higher costs for supplying Native Load." *Id.*, ¶ 2.1.1 through 2.1.7.

b. <u>The IPC-E-00-13 Case</u>. In Order No. 28596 issued December 19, 2000, the Commission approved the Agreement between IES and Idaho Power. Terms of the Agreement provide that it does not become effective until the state regulatory commissions of Idaho, Oregon, and Nevada all approve the Agreement in addition to the Federal Energy Regulatory Commission (FERC). Agreement at ¶ 6. The Agreement provides that it "shall not become effective until the commissions have issued their respective final orders approving the

Agreement or any future amendments." *Id.* at ¶ 9. With this background, we now turn to the particular concerns raised by the Staff comments in this case.

The Staff expressed several concerns regarding the trading practices and transactions. In addition, other parties questioned the prudency or practices of the Company's power purchases. These are discussed in further detail below.

2. Lack of Authority. As a threshold matter, the Staff asserted that the IES Agreement (including the Mid-C Pricing Index contained in the Agreement) is not in force because the Agreement had not been approved by the FERC or the Oregon Public Utility Commission. Consequently, Staff argued the market functions continue to be under Idaho Power and the Mid-C pricing structures should not be solely utilized. Staff Comments at 22-23. In Staff's view, Idaho Power should still be performing these trading transactions on its own behalf. If Idaho Power is still responsible for power purchases, it appears inappropriate and unreasonable to charge ratepayers $51 million more than the cost of the purchased power.

3. Hedging. Staff also expressed concern with the Company's apparent failure to properly use hedging instruments. Staff maintained that the Company has substantially limited long-term purchase contracts in favor of more expensive day-ahead market purchases. The Staff argued that the ability "to purchase power at a fixed price is a valuable tool for rate stability." According to Staff, the Company should have been aware of generating shortfalls and that its system would need to rely more heavily on expensive day-ahead markets. Staff Comments at 22.

After reviewing the Company's recent power purchases, the Staff determined that the Company only executed one power purchase contract in the month of February 2001 that was over a month in duration. Staff argued this apparent failure to properly hedge subjected ratepayers to greater market volatility and risk. *Id.* By comparison, Staff found during the months of June 2000 through August 2000, 30.5% of the Company's non-system purchases were term purchases of one month or more and an additional 60.2% were from the day-ahead market. In January and February 2001, 15.2% of the Company's non-system purchases were long-term and 70.3% were day-ahead transactions. This increased reliance on more expensive day-ahead markets is one factor that Staff believes has contributed to the overall increase in costs to ratepayers. *Id.*

4. Transaction Pricing

a. Mid–C Price Index. Staff recommended that a portion of the purchased power component of the PCA be deferred until the Commission re-examines the use of the Mid-C Pricing Index.[11] Staff Comments at 20-22, 29. Staff analyzed all transactions for the three months from December 2000 through February 2001, comparing purchases for the Company's operating system and non-operating system. The analysis showed that in 155 out of 161 transactions (more than 96%), the regulated entity paid more for power than was paid by the non-regulated entity. *Id.* at 23; Atch. Nos. 7-10. The Staff argued that the Mid-C pricing mechanism adopted in the Idaho Power-IES Agreement no longer represents a reasonable surrogate price for system power transactions. "[T]he Mid-C pricing does not produce rates that are fair, just and reasonable." *Id.* at 23.

To correct this pricing inaccuracy, Staff recommended that purchases by IES for Idaho Power be priced at the "lower of cost or market." Under a typical "lower of cost or market" approach for prudent and reasonable expenses, system units owned by the Company would normally be operated and dispatched if the cost of running these units was below alternatives available from the market. If market alternatives were less expensive, purchases would be made to take advantage of these lower costs for customers. Staff Atch. 19 at 4. The Staff argued that for purposes of determining the "market price," the Commission could use the Mid-C price or another acceptable pricing mechanism. Staff recommended that the cost be based on the daily weighted average of the price actually paid for the power by the non-operating book to third parties. *Id.* at 28.

In its reply comments, Idaho Power argued that the Mid-C Index continues to represent a relevant market price to use for affiliate transactions because it is the closest trading hub and is a liquid, objective pricing point. The Company maintained that it should be entitled to rely upon the Commission's previous orders and should be authorized to collect the $51,234,902 amount the Staff would "re-price" under a yet undefined methodology. Response at 7-8. The Company asserted that Order No. 28596 explicitly approved the Mid-C pricing mechanism contained in the Agreement. *Id.* at 9. Consequently, the Company claimed that it "has followed both the letter and the spirit of [the Order] in all of its actions." *Id.*

[11] The Staff recommended both an adjustment be made below the line and that the Commission investigate this issue in a "second phase or a separate case." Staff Comments at 29.

The Company stated there are additional advantages to the use of the Mid-C Index. Utilizing the Mid-C Index eliminates the ability of Company personnel to manipulate the price and they have no ability to pick and choose which transactions to classify as operating or non-operating. *Id.* at 11. The Company insisted that changing "the affiliate pricing procedures without prior Commission review is equally inappropriate and would result in retroactive ratemaking." *Id.* The Company also noted that the FERC believes an established relevant market index adequately mitigates affiliate abuse concerns. "Moreover, this is exactly what Idaho Power proposed and this Commission approved in Order No. 28596." *Id.* at 12.

b. Weighted Average. Staff also maintained that in the past real-time power purchases always flowed through the system at their actual costs. After conducting its review, Staff insisted that the Company is now pricing these transactions on the weighted average price for all real-time transactions that touch the Idaho Power system on an hourly basis. Staff Comments at 24. According to Staff's analysis, this results in overcharges and underpayments in several cases. Adjusting the inter-book real-time sales and purchases for the months of December 2000 through February 2001, Staff calculated that an adjustment of $4.6 million is necessary.[12] *Id.* The Staff's calculations are shown in Staff Attachment Nos. 7-10 and summarized on Staff Attachment No. 13.

The Company in its reply comments objected to the Staff's proposed adjustment. It argued setting transfer prices at the weighted average of all real-time affiliate transactions would expose the regulated utility to "risks, volatilities and costs of other markets outside the physical markets available for actual supply or sale of energy from the Idaho Power system." Reply at 14. The Company maintained that using the Staff's suggested methodology, the $24.4 million ratepayer benefit would in all actuality result in a $21 million detriment. *Id.* at 15. Furthermore, the Company maintains that any change in this pricing methodology could only be applied prospectively.

5. Transmission Pricing. Finally, Staff expressed concern that IES is utilizing the Company's transmission facilities without proper benefit or compensation to the regulated utility and its customers. Staff Comments at 25. For example, the Staff suspected that IES may be using "flip" transmission transactions. A "flip" occurs where power is received at one point in

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[12] The actual amount would be lower when adjusted for jurisdictional and sharing allocations.

the Company's transmission system and is delivered at another point. *Id.* For its part, the Company maintained that during the current PCA year alone, "the non-operating business paid $55,839,701 in transmission expenses and booked a credit reserve of $21,682,000." Reply at 14.

Commission Findings. Based on the above-mentioned comments, the reasonableness and prudency of several of Idaho Power's trading practices is directly disputed by the Staff, as well as indirectly by Intervenors. Moreover, we find that there is a legitimate dispute whether the Idaho Power/IES Agreement was actually in effect during the 2000-2001 PCA year. The Company's reply comments did not address the approval status of the Idaho Power/IES Agreement before either the Oregon or Federal Energy Regulatory Commissions.[13]

The Commission also finds that Staff has made a sufficient case for us to examine in greater detail the hedging practices of the Company. Reducing the use of long-term contracts, as we have seen in California, places over-reliance on the spot market and exposes utilities to possible exercise of market power by wholesale power sellers during periods of short supply. *California Power Exchange Corp. v. FERC*, ___ F.3d ___, 2001 WL 366364 (April 1, 2001). Consequently, we find it appropriate and in the public interest to examine the hedging issue more closely.

The Commission further finds that an investigation of the Mid-C Price Index is appropriate so that we may determine whether the charges proposed and the Company are reasonable. The Staff and other parties question the Company's power purchase practices. Although we recognize that use of the Mid-C Index was contemplated by our Order No. 28596 in Case No. IPC-E-00-13, Staff has raised the issue of whether the Agreement is in effect without all the other regulatory approvals. In addition, we find it necessary to review whether the Mid-C Index is an appropriate safeguard to determine the reasonableness of transactions between IES and Idaho Power. The Commission further finds that it is appropriate to examine Staff's allegations that IES/Idaho Power changed the manner that it purchased term power and billed/priced real-time power purchases. The Staff proposed an adjustment, to which the Company objects. Another disputed issue appears to be whether IES is appropriately

[13] After the record was closed in this case, the Federal Energy Regulatory Commission (FERC) issued an Order on April 27, 2001 concerning the Idaho Power/IES Service Agreement in Docket No. ER01-1329-000. In its Order, FERC approved the use of the Mid-C Index and the Palo Verde Index for day-ahead transactions. The FERC requested further filings for real-time transactions.

compensating Idaho Power for use of the transmission system. Given these disputes, the Commission exercises its discretion to also set these matters for hearing.

In summary, the Commission finds that these issues taken collectively raise sufficient concerns that an evidentiary hearing is required to fully develop the record in this case.

Until the hearing is complete and an order is issued, the Commission finds it necessary to defer recovery of the $51,234,902 in disputed pricing of power purchases. This hearing will also satisfy the concerns of the Industrial Customers of Idaho Power and others, who specifically objected to Modified Procedure and requested that a hearing be scheduled. A Prehearing Conference to set further proceedings will occur on **MAY 10, 2001 AT 10 A.M.** See Notice of Prehearing Conference Section below. To complete a review of these issues, the Commission finds it is appropriate to further suspend portions of the Company's Applications (IPC-E-01-7 and IPC-E-01-11) until such time as the Commission has completed its review of these issues.

B. The Disputed November Transaction

In its comments, Staff identified one transaction which also deserves further investigation by the Commission. For purposes of identification, we shall refer to it as the "November Transaction." An explanation and examination of this issue requires some background information. Idaho Power's parent corporation IDACORP has created a Risk Management Committee which maintains general oversight of energy commodity trading and assessments of financial risk. Staff Comments at 25. The Committee meets regularly to review "the profit and loss reports, exposure reports, strategies and program objectives. Decisions of the Committee are made by a simple majority and recorded in the minutes." *Id.* As described by the Staff, the Committee normally meets to evaluate whether Idaho Power needs to purchase off-system generation or whether it has system generation to sell. Once the Committee makes a decision regarding the purchases or trades, the purchase order is sent to the energy trader at IES "via e-mail and the traders carry out the orders of the [Committee] immediately." *Id.* at 26.

In reviewing the Committee minutes, the Staff focused on a particular Committee event in November 2000. The Staff alleged that the Committee instructed the energy trader to buy power that would be necessary to meet Idaho Power's future system needs in January 2001. Staff claimed that the November buy order of the Committee was not carried out. When a purchase was subsequently made to meet this need, the Staff alleged that the market price of power had substantially increased.

When the Staff inquired about this issue, the Company replied that the Committee minutes do not accurately reflect what happened. According to the Staff, the Company stated that after the Committee discussed making a purchase, it was decided by the Committee that no purchase would be necessary. However, the minutes do not reflect this subsequent discussion or action. Consequently, the Staff recommended that the Company's power purchase expense be reduced by $10,286,154 to reflect the difference between the market price of a timely executed purchase in November 2000 and the subsequent purchase at a higher price. *Id.* at 39.

In its response, the Company calculates the Staff's adjustment to be $7,976,701 million. The difference between the Company's calculation and Staff's calculation was premised upon the Company using Idaho jurisdictional data that would pass through the PCA, whereas the Staff was using multi-state system data. Response at 3-4. Idaho Power responded that this issue "is more of a dispute over appropriate recordkeeping than an error in trading activities." *Id.* at 4. Given the dispute concerning this issue, the Company requested that this matter be immediately set for hearing to determine the appropriateness of Staff's recommended denial.

Commission Findings. The Commission finds that there are considerable concerns regarding the November transaction and that they do not necessarily lend themselves to resolution by the submission of written comments. As is customary of most PCA cases, the Staff and intervenors generally examine the books and records of the Company to determine the validity or reliability of entries. In this instance the Staff has challenged the appropriateness of this action and recommended an adjustment to the PCA request. The Commission believes that it is necessary to conduct an evidentiary hearing in this matter. There is sufficient cause to examine this transaction in greater detail. An evidentiary hearing will afford all parties an opportunity to adequately develop the record so that the Commission can make an informed judgement. Consequently, the Commission will defer recovery of $7,976,701 million and will schedule an evidentiary hearing on this issue. See Notice of Prehearing Conference Section below. To complete our review of this issue, the Commission finds it is appropriate to further suspend portions of the Company's Applications (IPC-E-01-7 and IPC-E-01-11) until such time as the Commission has completed its review of this matter.

C. Resource Planning

In its comments, Staff concluded that the Company made market purchases this winter in exact accordance with its long-term integrated resource plans (IRPs). Although Staff did not call Idaho Power's resource planning imprudent, it noted that these purchases were made despite increasingly severe warnings found in Western Systems Coordinating Council (WSCC), North American Energy Reliability Council (NERC) and Northwest Power Planning Council (NWPPC) reports. Staff Comments at 19-20.

The Industrial Customers of Idaho Power (ICIP) argued that Idaho Power has not made a showing sufficient to allow the Commission to find that its power purchases over the past PCA year have been prudent or that the extraordinary expenses it incurred were not necessitated by lack of planning. ICIP Comments at 2. The ICIP further stated that the Company has been imprudent in its failure to actively promote energy conservation measures and independent power production in its service territory. *Id.* Therefore, it urged the Commission to review the Company's load and resource plan and determine to what extent the extraordinary power supply costs resulted from Idaho Power's load and resource planning decisions. *Id.* at 8.

Likewise, the Idaho Rural Council wrote that a substantial portion of the power costs Idaho Power seeks to recover resulted from its failure to take reasonable measures to anticipate and satisfy its customer's electricity needs. Rural Council Comments at 6. It argued that the Company knew 1) it had a growing customer base, 2) that it lacked new power generation, and 3) of the Northwest Power Planning Council's concerns. *Id.*

The U.S. Department of Energy (DOE) also recommended that the Commission examine the details of Idaho Power's power supply procurement procedures. DOE Comments at 5. In a similar vein, the Idaho Irrigation Pumpers Association indicated its desire to investigate in an evidentiary hearing what steps the Company took to secure short-term firm purchases during months when it knew it would be short of generation due to low water and review the time period when the Company began "to shift from its reliance upon non-firm to short-term purchases." Irrigation Pumpers Comments at 2.

Commission Findings. Several parties and a considerable number of public comments allege that Idaho Power's long-term planning and/or failure to deviate from or adjust long-term plans contained in its IRPs were imprudent in light of known water and market conditions.

Last December the Commission acknowledged and accepted Idaho Power's 2000 IRP "for filing" in Order No. 28583 (Case No. IPC-E-00-10). As noted in the Integrated Resource Planning Statement of Policy adopted in Order No. 25260:

> ...the filing of the plan does not constitute approval or disapproval of the plan having the force and effect of law, and the deviation from the plan would not constitute violation of the Commission's orders or rules. The prudence of a utility's plan and the utility's prudence in following or not following a plan are matters that may be considered in a general rate proceeding or other proceeding in which those issues have been noticed.

Order No. 25260 at 4 (Case No. GNR-E-93-3). While the Commission does not intend to review the IRPs, the Commission will accept further evidence whether the Company's resource planning is flexible enough to adjust for current water and market conditions. The scheduling of discovery and other hearing issues will be determined at the Prehearing Conference set for May 10, 2001. See Notice of Prehearing Conference in Section IV below.

To facilitate this limited review, the Commission directs Idaho Power to file with the Commission a report outlining short-term plans for the summer and winter of 2001. The report should show projected loads, anticipated traditional resources, resources acquired to reduce market exposure, energy provided by each resource, costs paid for each resource, surplus/deficit energy for summer loads, market resource plans and anticipated cost.

IV. NOTICE OF PREHEARING CONFERENCE

YOU ARE HEREBY NOTIFIED that a Prehearing Conference has been scheduled to commence at **10:00 A.M. ON THURSDAY, MAY 10, 2001, AT THE COMMISSION HEARING ROOM, 472 WEST WASHINGTON STREET, BOISE, IDAHO, (208) 334-0300**. The purpose of the Prehearing Conference is to establish a hearing schedule to consider those issues described above that the Commission has determined warrant further investigation. More specifically, the Commission intends to conduct an evidentiary hearing to examine the following issues: trading practices (to include hedging, transmission and wheeling charges, Mid-C pricing, and the use of weighted average pricing), the November trading event, and the Company's resource planning.

YOU ARE FURTHER NOTIFIED that the Commission's examination of the trading practices, pricing mechanisms, and the Company's Services Agreement with IES, may result in amendments to Order No. 28596 issued December 19, 2000 in Case No. IPC-E-00-13. See *Idaho Code* § 61-624.

YOU ARE FURTHER NOTIFIED that the Commission's final determination of the issues subject to further investigation may ultimately result in the Company's recovery of PCA revenue in excess of that amount authorized to be collected in this Order. Consequently, the rates and charges for all Idaho customers, both recurring and non-recurring, including special contract customers, are at issue and every component of every existing and proposed rate and charge is at issue. The Commission may ultimately approve, reject or modify the rates and charges proposed. It may also find that rates and charges different from those proposed by any party are just, fair and reasonable.

YOU ARE FURTHER NOTIFIED that the remaining PCA issues to be examined in the subsequent evidentiary proceeding, consistent with the Company's Applications in the combined PCA filing, represent approximately $59 million in PCA revenue. Recovery of this amount through a flat charge per kWh would result in an additional rate increase of .4468¢ per kWh imposed on all customers for 12 and one-half months. The rates decided in this Order and the potential rate impact of the issues yet to be decided is set out below for each customer class:

CUSTOMER GROUP	APPROVED[14] AVERAGE RATE	POTENTIAL AVERAGE RATE	POTENTIAL INCREASE OVER CURRENT RATES
Residential			Gp. Avg. 32.7%
First Block	5.7 cents per kWh	6.0 cents per kWh	20%
Second Block	6.5 cents per kWh	7.0 cents per kWh	40%
Third Block	8.1 cents per kWh	9.3 cents per kWh	86%
Irrigation	5.1 cents per kWh	5.5 cents per kWh	41.0%
Small Commercial	7.6 cents per kWh	8.1 cents per kWh	26.6%
Large Commercial	4.9 cents per kWh	5.3 cents per kWh	43.2%
Industrial	4.1 cents per kWh	4.5 cents per kWh	55.2%

YOU ARE FURTHER NOTIFIED that because the rates authorized in this Order and the revenue associated with those issues subject to further investigation clearly exceed 7% of the Company's normalized base revenues for the Idaho jurisdiction, the Commission may employ

[14] The PCA rates approved in this Order are discussed in more detail in Section VI on Rate Design.

other rate stability mechanisms including but not limited to deferring recovery until next year's PCA case. See Order No. 28406 at 19-20.

YOU ARE FURTHER NOTIFIED that all further hearings and prehearing conferences in this matter will be held in facilities meeting the accessibility requirements of the Americans with Disabilities Act. In order to participate, understand testimony and argument at a public hearing, persons needing the help of a sign language interpreter or other assistance may ask the Commission to provide a sign language interpreter or other assistance as required under the Americans with Disabilities Act. The request for assistance must be received at least five (5) working days before the hearing by contacting the Commission Secretary at:

IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, ID 83720-0074
(208) 334-0338 (TELEPHONE)
(208) 334-3762 (FAX)

YOU ARE FURTHER NOTIFIED that the parties participating in the prehearing conference may offer to settle some or all of the issues to be discussed at the prehearing conference.

YOU ARE FURTHER NOTIFIED that all proceedings in this case will be held pursuant to the Commission's jurisdiction under Title 61 of the Idaho Code and that the Commission may enter any final Order consistent with its authority under Title 61. The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-622, 61-623, and 61-624.

YOU ARE FURTHER NOTIFIED that all further proceedings in this matter will be conducted pursuant to the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq*.

V. CONSERVATION

Many of those who submitted written comments and testified at the public hearings called for additional conservation measures and the reinstatement of Demand-Side Management (DSM) programs. Until the late 1990s Idaho Power had several DSM programs in place, including the Commercial Lighting Program,[15] the Design Excellence Award Program,[16] the

[15] The Commercial Lighting Program was discontinued in February 1998 in Order No. 27375 (Case No. IPC-E-98-1).
[16] The Design Excellence Award Program for commercial customers was discontinued in 1997 in Order No. 26931 (Case No. IPC-E-97-2).

Partners in Industrial Efficiency Program[17] and the Agricultural Choices Program.[18] These programs were discontinued for a variety of reasons, including lack of customer interest, concerns regarding their additions to deferred accounts, completion of the program's original goal, and fear that grants to install energy-efficient equipment could potentially become stranded assets if deregulation were to occur. Idaho Power was not alone in the termination of DSM programs, other regulated electric companies in the region similarly terminated their DSM programs. In place of company-specific programs, Idaho Power participates in the Northwest Energy Efficiency Alliance (NEEA), a regional approach to conservation whose goal is long-term market transformation.

In addition to their comments, the Land and Water Fund of the Rockies, Idaho Rivers United, Idaho Rural Council, and Mary McGown filed a Motion to Reinstate Idaho Power's DSM programs. They further proposed that 10% of the funds sought by the Company in these cases be dedicated to the establishment of conservation and efficiency programs. Land and Water Fund Comments at 2. These intervenors also requested hearings to evaluate permanent programs, including industry and agriculture process-efficiency improvement programs, time-of-use metering for all classes, net-metered small generation systems, and encourage strong efficiency standards for local building codes. *Id.* at 12.

Although they did not file a motion to that effect, the Industrial Customers of Idaho Power also support the revival of Idaho Power's previous DSM programs. They offer to implement industrial specific conservation measures that would utilize the funds currently paid to Idaho Power by the industrial class for the NEEA. ICIP Comments at 9-10.

Recognizing the value of DSM Buy-Back programs like those recently instituted for irrigators and Astaris, Staff suggested the Company provide a loan program that would allow customers to borrow money at a low interest rate, with low initiation fees, and amortize the loan over the life of the installed conservation measure. Staff Comments at 33. Any viable conservation measure for any customer class would be eligible. Staff argues that customers would then be empowered to reduce their energy use, saving on their bills and reducing the utility's dependence on the market.

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[17] The Partners in Industrial Efficiency Program was discontinued in February 1997 in Order Nos. 26753 and 26957 (Case No. IPC-E-96-22).

[18] The Agricultural Choices Program was discontinued in July 1998 in Order No. 27637 (Case No. IPC-E-98-4).

Commission Findings. The Northwest River Forecast Center estimated that as of April 1, 2001, Snake River Basin streamflows are only 33% of normal. This is critical because in a normal water year, Idaho Power generates approximately 60% of its total system requirements from its hydropower facilities.[19] With less water available to generate hydroelectricity, the Company is forced to generate more costly thermal power and to purchase additional off-system power to meet its retail customer requirements. The western wholesale energy market has been extremely volatile since last summer, in large part due to chronic supply shortages in California and poor hydro generation conditions throughout the West. According to the *Wall Street Journal*, average wholesale power prices have increased more than ten times from prices one year ago.[20] Consequently, Idaho Power's energy purchases under these market conditions have created the extraordinary short-term expense that it seeks currently to recover. Although the Commission hopes otherwise, it is entirely possible that Idaho will continue to have poor water conditions and the regional power market will remain astronomically expensive.

In granting the rate increase authorized by this Order, the Commission recognizes that consumers need avenues to reduce their consumption. Conservation and DSM programs are powerful tools Idahoans can use to mitigate the impact of this rate increase as well as ones that may occur in the future. Furthermore, the Commission agrees with the Land and Water Fund of the Rockies, Mary McGown, Idaho Rivers United and the Idaho Rural Council that "basic fairness demands that all rate classes be afforded the opportunity to enjoy the benefits of guided conservation and efficiency improvements" comparable to the recently authorized irrigation and Astaris Buy-Back programs. Land and Water Fund Comments at 2.

The Commission believes that reinstating a comprehensive conservation program is now appropriate given the current volatility of market prices and the opportunity to incorporate long-term conservation. Consequently, the Commission now opens a DSM docket in Case No. IPC-E-01-13. Idaho Power is directed to file a comprehensive DSM program by August 1, 2001 that details program structure, potential conservation measures to pursue and funding options that include a tariff rider. In particular, the Company should consider addressing conservation proposals for residential customers in the highest block rate that typically use electric space

[19] IPUC Comments in FERC Docket No. RM95-8-000 and Docket No. RM94-7-001 at 3 (August 4, 1995).

[20] Gavin, Robert, *Some Utilities Rake in Revenue Amid California Energy Crisis*, Wall St. J., Feb. 23, 2001.

heating. The Company's subsequent filing will be subject to review by all interested parties prior to final decision by the Commission.

VI. RATE DESIGN

Rates are normally adjusted each May once the Commission determines the appropriate revenue increase or decrease under the Company's PCA. As previously mentioned, the Company's combined PCA filing sought to recover approximately $227.4 million through the imposition of a flat 1.8889¢ per kWh charge imposed on all its customers over a 12-month period. Because not all customers pay the same kWh charge, the proposed 1.8889¢ per kWh represents a different percentage increase for each customer class. The percentage impact of the Company's proposed rate increase for most customer classes is set out below:

CUSTOMER GROUP	TODAY'S AVERAGE RATE	PROPOSED AVERAGE RATE	PERCENTAGE INCREASE
Residential	5.2 cents per kWh	7.1 cents per kWh	34.4%
Irrigation	3.9 cents per kWh	5.8 cents per kWh	46.8%
Small Commercial	6.4 cents per kWh	8.3 cents per kWh	27.9%
Large Commercial	3.7 cents per kWh	5.5 cents per kWh	49.6%
Industrial	2.9 cents per kWh	4.7 cents per kWh	62.8%

Source: Order No. 28685 at 3.

The Company requests that the new PCA rate become effective on May 1, 2001.

A. Non-Residential Rates

In its comments, the Staff recommended that all customer rate groups, except the residential schedule,[21] be increased on a uniform cents per kWh basis. Staff Comments at 32. Although Staff did consider implementing inverted block rates for other customer classes, it concluded that using inverted block rates for non-residential classes is not warranted at this time. *Id.* at 33. The Staff concluded that the uniform rate increase for non-residential customers will provide a "clear message to conserve wherever it is cost effective." *Id.* In addition to residential inverted block rates, the Land and Water Fund recommended that block rates be implemented for commercial, industrial and agricultural customers. Land and Water Fund Comments at 3.

Commission Findings. We agree with the Company and Staff that the rate increases for irrigation, commercial and industrial customers should be implemented on a uniform 1.2044

[21] Rates for residential customers are discussed separately below.

cents per kWh charge imposed on all customers over a 12 and one-half month period. This rate design produces a PCA rate of 1.3415¢ per kWh above base rates. Appendix 2 shows all of Idaho Power's affected schedules and the associated average rates and increases. The table below is a simplified version of Appendix 2.

CUSTOMER GROUP	EXISTING AVERAGE RATE	APPROVED AVERAGE RATE	PERCENTAGE INCREASE
Irrigation	3.9 cents per kWh	5.1 cents per kWh	31.3%
Small Commercial	6.4 cents per kWh	7.6 cents per kWh	18.8%
Large Commercial	3.7 cents per kWh	4.9 cents per kWh	32.9%
Industrial	2.9 cents per kWh	4.1 cents per kWh	42.1%

Imposing a uniform cents per kWh surcharge is reasonable and consistent with past PCA surcharges. We next turn to the rates for residential customers.

B. Residential Rates

Although the Company proposed that residential rates also be uniformly increased, the Commission Staff recommended that the Commission adopt an inverted three-block rate design for residential customers. Under the Staff's proposal, residential rates would increase in each block as a customer's usage increased. For example, the rates for usage between 0 and 800 kWh would increase 12% over existing base rates. For usage in the second block (between 801 and 2000 kWh), rates would increase by 24.1%. Rates for the third block would increase by 51.7% for all usage over 2000 kWh. Staff Comments at 31; Atch. No. 16.

Staff maintained that adoption of the three-tiered inverted block rates would give a stronger conservation signal and would be easier to implement and administer than other block rate designs. The Staff claimed that this rate design for residential customers places a greater portion of the rate increase on customers using electric space heating. Electric space heating is the primary cause of the winter peak demand for residential customers. *Id.* at 32. Staff noted that the cost of space heating has increased dramatically for all fuels except electricity in the last two years. While the electric space heating customer's energy costs have actually <u>decreased</u> over the last two years, the energy cost of natural gas space heating customers have increased by 32%. *Id.* at 31. Consequently, inverted block rates would mitigate those differences and place a greater portion of the rate increase on users of large amounts of electricity.

The Staff's analysis of annual residential usage showed that 44% of customers would be billed entirely in the first block, 43% of residential customers would be billed in the first and second blocks, and 12% of customers would be billed in for usage in all three blocks. *Id.* A similar trend is evident when considering residential usage. Staff's Attachment No. 15 showed that the vast majority of residential kWh were billed in the first block, 31% in the second block, and only 11% in the last block. The majority of the kWh in the last block occurred during the winter heating months. *Id.*

Other parties also supported imposition of a block rate design for residential customers. The Irrigation Pumpers recommended that an inverted block rate design be implemented with the ceiling for the first block set at 400 kWh. Irrigation Pumpers Comments at 3. The Land and Water Fund also recommended block rates for residential customers. It suggested that the first 500 kWh of energy should be billed at current rates "and any consumption above that amount subject to an increased rate." Land and Water Fund Comments at 3. The Fund insisted that block rates would protect low- and fixed-income customers from rapid swings in electricity rate and encourage conservation.

Commission Findings. Based upon our review of the record, we find it is appropriate and reasonable to implement a three-tiered block rate design for residential customers. There are several reasons supporting our adoption of this rate design. First, as the Staff and Land and Water Fund observed, tiered-rates provide residential customers with appropriate price signals to conserve electricity. In other words, the more electricity used by a customer, the greater the rate. This structure provides an effective and efficient means of providing customers with incentives to conserve electricity.

As the Staff pointed out in its comments, 87% of all bills rendered during the year would occur in the first two blocks and approximately 90% of all residential usage occurs in the first two blocks. Under a uniform rate increase, residential rates would have increased 23.1%. Under our tiered rate design, the PCA surcharge will be: first block 0-800 kWh, .8049¢ per kWh (14.4% over current rates); second block, 801-2000 kWh, 1.6098¢ per kWh (a 28.8% increase); and third block for kWh in excess of 2000, 3.4586¢ per kWh (a 62% increase). Under the rates adopted in this Order, only 12% of customers' usage is expected to reach the top block rate. Thus, the vast majority of residential customers will receive a rate increase below what would have occurred with a uniform rate increase.

While we recognize that some customers may not be able to conserve or reduce their consumption, there are programs for eligible residential customers to possibly convert to more efficient space heating appliances or receive assistance for high heating bills. For example, customers may enroll in levelized pay programs that are intended to reduce or "levelize" bills for high consumption months with bills for low consumption months. Low-income customers may also be eligible to receive financial assistance from energy programs like LIHEAP, Project Share, and Project Warmth. The Commission Staff or the community action agency may be able to provide additional information on these programs. Customers interested in conserving energy may also view the U.S. Department of Energy's website located at www.eren.doe.gov/buildings/documents/high_heating_bills. The Idaho Office of Energy also dispenses low interest energy conservation loans. Interested persons can access applications and additional information on their website at: www.idwr.state.id.us/SaveEnergy/Residential.htm. Finally, the Commission's winter moratorium rule prohibits any electric or gas utility from terminating or threatening to terminate service during the months of December through February of any residential customer who declares that he or she is unable to pay in full for utility service and whose household includes children, the elderly, or infirmed persons. IDAPA 31.21.01.306.01. However, for families that use this protection, the full amount not paid during the moratorium period becomes due on March 1.

The Commission also notes that the possibility of imposing a tiered-rate design for residential customers was discussed at every public meeting. Customers asked about the imposition of inverted rate block generally said that this mechanism could potentially be very effective in promoting residential conservation. Irrigators and business owners noted that they had little ability to alter their consumption and thus, block rates would not be as effective for them.

C. Amortization of Rates

Under normal operations, the PCA surcharge or credit is effective over a 12-month period. Staff recommended that if the Commission approved an overall rate increase greater than 20%, that the Commission should consider amortizing (or spreading) the increase over two years. Staff Comments at 6.

The ICIP also requested that the recovery of this year's PCA occur over five years. The ICIP maintained that five years is the minimum length of time needed to ameliorate the rate shock effect of the large rate increase. ICIP Comments at 13. The Idaho Rural Council also requested that any rate increase granted to Idaho Power be spread over five years to reduce its impact on low-income and fixed-income families, farmers and farming communities. Rural Council Comments at 3. The U.S. Department of Energy also asked the Commission to consider deferring a portion of the proposed rate increase. However, the Department did not specify a specific time period. DOE Comments at 5. Idaho Power's response did not specifically address amortization but expressed its belief that recovery deferral is "bad policy." Response at 3.

Commission Findings. While the Commission is sympathetic to the request that the authorized rate increase or some portion thereof be amortized over time, the Commission declines to adopt this recommendation. As with any requested rate increase, the Commission must balance the needs of the Company to maintain its financial viability with customer concerns of fair rates and rate stability. In this case, the Commission is confronted with extraordinary conditions that resulted in large purchase power costs and a low forecast of water. Given the amount of purchases the Company has already made, it is reasonable and appropriate for the Company to recover these costs within the normal one-year timeframe.

This is not to say that amortization is not a viable option. We noted in the original PCA Order that when the PCA results in large rate increases, it may be appropriate to defer a percentage of that year's power supply costs. Order No. 24806 at 20. The Commission intends to explore this and other rate stability mechanisms when we examine those issues that are deferred for further investigation. Because several matters have yet to be decided, we do not address the merits of the deferral issue but place the Company on notice that the Commission will determine the appropriate manner of any recovery for these deferred issues at a later time.

D. Effective Date

The Company requested that the PCA rates become effective on May 1, 2001 whereas the Staff recommended that the PCA rates become effective on May 16, 2001. The Staff explained that the reason for the May 16 date was that last year's PCA rate runs through May 15, 2001. To avoid the apparent overlap, the Staff recommended that the PCA rates in this case become effective on May 16. Staff Comments at 6.

In its reply comments, the Company indicated that implementing rates on May 1 would not cause a problem because the Company envisioned terminating the existing PCA rates on April 30. The Company noted that the Commission's suspension of the February Application was until May 1. The Company also stated that financial institutions, rating agencies, and customers anticipate the implementation of new PCA rates on May 1.

If the Commission determines that the appropriate effective date is May 1, the Company proposes that the new rate reflect the uncollected revenue from last year's PCA from May 1 to May 15 and offset by the unrefunded amount from last year's revenue sharing adjustment. Response at 20. The Company also proposed that a final adjustment to collect the true-up revenues over 12 ½ months would be an appropriate adjustment. *Id.,* Response Attachment A, p. 1.

Commission Findings. We find that the appropriate date to implement the PCA rates granted in this Order is May 1, 2001. As the Company noted, customers and financial institutions anticipate that the Commission will implement new PCA rates on May 1. We also find that it is reasonable to adopt the Company's proposed adjustment to reconcile the overlapping PCA and revenue sharing rates. See Appendices 1 and 2 to this Order.

In summary, the Commission is authorizing Idaho Power to recover approximately $168.3 million, or approximately 74% of its requested PCA revenues. This amount is $159.63 million above current rates. The balance of the Company's request is deferred pending our further investigation into several issues. The Commission is ordering implementation of the PCA rate changes effective on May 1, 2001. We believe that allowing the Company to recover the customers' share of its above normal power costs in a timely fashion ensures the Company of continued financial viability and, at the same time, protects ratepayers from what may be imprudent or unreasonable transactions. It is our intent to move expeditiously to resolve the remaining issues in this case.

ORDER

IT IS HEREBY ORDERED that Idaho Power Company's PCA Applications in these cases are partially granted. The Company is authorized to implement the rates identified in this Order, which will generate approximately $168.3 million in PCA revenues.

IT IS FURTHER ORDERED that recovery of the disputed amount of $51,234,902 involving the Company's trading practices and the $7,976,701 associated with the disputed November transaction will be deferred until such time as those matters are resolved.

IT IS FURTHER ORDERED that those issues in Idaho Power Company's Application in Case No. IPC-E-01-7 that are deferred for further investigation, are further suspended until August 23, 2001, or until such time as the Commission may issue a final Order accepting, rejecting, or modifying the requested rate increase as it relates to the deferred issues.

IT IS FURTHER ORDERED that those issues in Idaho Power Company's Application in Case No. IPC-E-01-11 which are deferred for further investigation, are further suspended until August 23, 2001, or until such time as the Commission may issue a final Order accepting, rejecting, or modifying the requested rate increase as it relates to the deferred issues.

IT IS FURTHER ORDERED that the Company shall file tariffs in conformance with a uniform kWh rate increase of 1.2044¢ per kWh for all non-residential classes. The new PCA tariff rate shall be 1.3415¢ per kWh.

IT IS FURTHER ORDERED that the Company file tariffs in conformance with the inverted block rate for residential customers previously described in this Order.

IT IS FURTHER ORDERED that the PCA rates established in this Order are effective May 1, 2001.

IT IS FURTHER ORDERED that the rate adjustments for PCA undercollection and unrefunded revenue sharing associated with a May 1, 2001 effective date be included in this year's PCA rate. The adjustments have been included in the ordered rates shown in Appendix 2.

IT IS FURTHER ORDERED that the March 2001 above forecast power supply costs are deferred until next year's PCA case.

IT IS FURTHER ORDERED that a Prehearing Conference to establish a hearing schedule for the issues to be investigated shall take place on May 10, 2001 at 10 a.m. in the Hearing Room of the Idaho Public Utilities Commission.

IT IS FURTHER ORDERED that the Motion to Reinstate Demand-Side Management Programs filed by the Land and Water Fund of the Rockies, Mary McGown, Idaho Rivers United and the Idaho Rural Council is partially granted in that the Commission initiates an Idaho Power Demand-Side Management docket in Case No. IPC-E-01-13. Idaho Power is directed to file a comprehensive demand-side management program by August 1, 2001 that details its program's structure and funding options.

THIS IS A FINAL ORDER AS TO SOME ISSUES. Any person interested in issues finally decided by this Order or in interlocutory Orders previously issued in these Case Nos. IPC-

E-01-7 and IPC-E-01-11 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter finally decided in this Order or in interlocutory Orders previously issued in these Case Nos. IPC-E-01-7 and IPC-E-01-11. For purposes of filing a petition for reconsideration, this order shall become effective as of the service date. *Idaho Code* § 61-626. 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 30th day of April 2001.

PAUL KJELLANDER, PRESIDENT

See Separate Concurring Opinion
MARSHA H. SMITH, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

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SEPARATE CONCURRING OPINION
OF
COMMISSIONER MARSHA H. SMITH

CASE NOS. IPC-E-01-7 AND IPC-E-01-11
ORDER NO. 28722

Because I support nearly all the findings in this Order, I characterize this as a separate opinion, not a dissent. I have two concerns about the deferral of $51,234,902 until further evidentiary hearings are held. First, Commission Orders and directives remain in effect until changed. It seems that we are stretching this important regulatory principle based on a technicality. Second, pushing recovery of costs into the future will cost more and extend the ratepayer burden for the power costs of this past year.

In Order No. 28596, issued December 19, 2000, the Commission approved a methodology to price sales and purchases between Idaho Power and IES. This followed about two years of work between the Company and the Staff. The Staff supported the agreement and recommended approval. Two public workshops were held and written comments were filed by a number of interested persons. The Commission concluded:

> Regarding the IPCo/IES Agreement, we find that the Agreement establishes a reasonable and transparent structure for prioritizing, protecting and serving native load requirements. We are convinced that the Agreement gives the Company's native load customers priority and the economic use and dispatch of Company generation resources, transmission and distribution facilities. In distinguishing between operating and non-operating transactions, it also provides a reasonable means of assuring that the Company's native load customers are not saddled with those risks unrelated to providing regulated utility service.

Order No. 28596 at 10.

We also charged the Staff with continuing audit and review of the dealings between the Company and its affiliate. The Commission should review the methodology regularly to be sure that it yields fair and reasonable results over time. Further review of the amount in dispute in this case is necessary and should be done with intense scrutiny. However, changes in Commission approved methodologies should be implemented prospectively. This has been a firm regulatory principle to ensure certainty and fairness. Here, the majority finds that because approvals of the Federal Energy Regulatory Commission and Oregon Public Utility Commission have not yet been obtained as required by the stipulation, the methodology adopted by our Order may not yet be in effect. Only in a technical legal sense could those approvals be seen as conditions precedent to the effectiveness of the Commission's Order. I note that FERC issued its Order on this matter last week.

My second concern is for the timing of the recovery of the power costs for the 2000-2001 PCA year. It will take some time to conduct the proceeding outlined in the Order. We have scheduled a prehearing conference almost immediately to avoid delay. However, I predict that by the time the proceeding is concluded, any amount deemed to be justified will be pushed forward for recovery in the next PCA. It will add to what we already know will be significant costs that will need to be considered next year. It seems likely that the 2001-2002 PCA costs may be securitized under the new authority granted by the legislature. If this is the case, ratepayers may still be paying off costs from 2000-2001 in 2007. While I reluctantly supported the enactment of the securitization bill, I have grave concerns with its use and had hoped it could be avoided. This deferral makes it more likely that the Commission will authorize the use of energy cost bonds, thus mortgaging the ratepayers' future.

I recognize that deferral of the $51 million mitigates this rate increase to a degree. I hope that the cost of deferral does not turn out to be an even greater burden over a longer period of time for Idaho Power's customers.

Marsha H Smith

COMMISSIONER MARSHA H. SMITH

2001-2002 PCA - Ninth Annual
IPC-E-01-7 & 11
Commission Decision

Description	Units	Base	Forecast	Difference	Rate
2001 - 2002 Forecast:					
PCA Expense	($)	73,079,128	132,938,867		
Normalized Energy - Total System	(MWH)	13,952,283	13,952,283		
Energy Rate	(Mills/kWh)	5.23779	9.52811	4.29032	
Sharing Percentage	(%)			90%	
Energy Rate Difference	(Mills/kWh)			3.861286723	3.861

		($)	(MWh)	($/MWh)	(Mills/kWh)
2000-2001 True-up		126,212,496.40	13,253,976	9.522613924	9.523
Other Adjustments:					
2000-2001 PCA Undercollection		662,976			
2000-2001 Unrefunded Rev. Sharing		(239,851)			
DSM Adjustment		(6,056)			
		417,068	13,253,976	0.03146741	0.031
PCA Rates:					
Proposed PCA Rate Adj. from Base	(Mills/kWh)				13.415
PCA Rate Currently in Effect	(Mills/kWh)				1.371
Total Rate Difference	(Mills/kWh)				12.044

Expected PCA Revenues:	Rate ($/MWh)	Energy (MWh)	Revenue ($)
Revenue Incr. - Expiring PCA to Proposed PCA	12.044	13,253,976	$159,630,887

Note: Negative rates and amounts indicate benefits to ratepayers.

Commission Decision
IPC-E-01-7 & 11
Summary of Revenue Impact
State of Idaho
Normalized 12-Months Ending December 31, 1999
5/16/00 PCA & Revenue Sharing Rates to 5/1/01 PCA Rates

Line No.	Tariff Description	(1) Rate Sch. No.	(2) 1999 Avg. Number of Customers	(3) 1999 Sales Normalized (kWh)	(4) 5/16/00 PCA Revenue	(5) Revenue Adjustments	(6) Proposed Total Revenue	(7) Average ¢/kWh	(8) Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1	299,321	4,076,279,049	213,546,646	49,094,705	262,641,351	6.443	22.99%
2	Small General Service	7	30,236	267,798,952	17,146,211	3,225,371	20,371,582	7.607	18.81%
3	Large General Service	9	14,287	2,724,587,690	99,770,296	32,814,934	132,585,230	4.866	32.89%
4	Dusk to Dawn Lighting	15	-	5,950,841	1,525,508	71,672	1,597,180	26.840	4.70%
5	Large Power Service	19	101	1,908,784,165	54,576,443	22,989,396	77,565,839	4.064	42.12%
6	Irrigation Service	24	12,343	1,678,547,071	64,573,718	20,216,421	84,790,139	5.051	31.31%
7	Unmetered General Service	40	806	9,441,291	521,380	113,711	635,091	6.727	21.81%
8	Municipal Street Lighting	41	84	15,816,545	1,826,084	190,494	2,016,578	12.750	10.43%
9	Traffic Control Lighting	42	56	11,968,722	370,592	144,151	514,743	4.301	38.90%
10	Sub-Total		357,234	10,699,174,326	453,856,878	128,860,856	582,717,734	5.446	28.39%
	Special Contracts:								
11	Micron	26	1	536,787,231	15,247,683	6,465,065	21,712,748	4.045	42.40%
12	FMC	28	1	1,051,200,000	24,660,319	12,660,653	37,320,972	3.550	51.34%
13	J R Şimplot	29	1	279,696,105	6,830,585	3,368,660	10,199,245	3.647	49.32%
14	DOE	30	1	203,547,709	4,824,251	2,451,529	7,275,780	3.574	50.82%
15	Sub-Total		4	2,071,231,045	51,562,838	24,945,907	76,508,745	3.694	48.38%
16	Total Annual Idaho Retail Sales		357,238	12,770,405,371	505,419,716	153,806,762	659,226,478	5.162	30.43%
17	Additional One-Half Month of May		0	483,571,000	0	5,824,129	5,824,129		
18	Adjusted Total Idaho Retail Sales		357,238	13,253,976,371	505,419,716	159,630,891	665,050,607		