BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-01-43

EXHIBIT NO. 3

GREGORY W. SAID

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT A POWER COST ADJUSTMENT TARIFF FOR ELECTRIC SERVICE TO CUSTOMERS IN THE STATE OF IDAHO AND FOR APPROVAL OF NEW RATES FOR SERVICE UNDER THE FMC SPECIAL CONTRACT.	CASE NO. IPC-E-92-25 ORDER NO. 24806

APPEARANCES

FOR IDAHO POWER COMPANY:	LARRY D. RIPLEY Idaho Power Company PO Box 70 Boise, ID 83707-0070
FOR COMMISSION STAFF:	MICHAEL S. GILMORE BRAD M. PURDY Deputy Attorneys General Idaho Public Utilities Commission Statehouse Boise, ID 83720-6000
FOR FMC CORPORATION:	CONLEY WARD, JR. Givens, Pursley & Huntley 277 N. 6th Street, Suite 200 PO Box 2720 Boise, ID 83701-2720
FOR INDUSTRIAL CUSTOMERS OF IDAHO POWER:	GRANT TANNER PETER J. RICHARDSON Davis Wright Tremaine 702 W. Idaho Street, Suite 700 Boise, ID 83702-8908
FOR IDAHO IRRIGATION PUMPERS ASSOCIATION:	RANDALL C. BUDGE Attorney at Law Racine, Olson, Nye, Cooper & Budge, Chartered 201 E. Center PO Box 1391 Pocatello, ID 83204-1391

COMMERCIAL UTILITY CUSTOMERS:

RONALD L. WILLIAMS
Eberle, Berlin, Kading, Turnbow & McKlveen, Chartered
300 North 6th Street
PO Box 1368
Boise, ID 83701-1368

FOR UNITED STATES FEDERAL EXECUTIVE AGENCIES:

LAWRENCE A. GOLLOMP
Assistant General Counsel
U.S. Dept. of Energy, Room 6D-033
1000 Independence Avenue S.W.
Washington, DC 20585

SYNOPSIS

On November 24, 1992, the Idaho Power Company (Idaho Power; Company) filed an Application for authority to implement a Power Cost Adjustment mechanism (PCA) and to adjust the rates of the FMC Corporation (FMC). By this Order, we adopt a PCA for Idaho Power. The mechanism we approve has the following basic elements: It is based on annual forecasted power supply costs; deviations from predicted annual power supply expense are deferred and trued-up in a subsequent year; interest is accrued on deferrals; an efficiency incentive shares variations in power supply costs from a base case between the ratepayers and the Company on a 90-10 ratio; a procedure to guard against rate shock is included; power supply costs associated with changes in load are factored out of the PCA; rate changes mandated by the PCA are recovered by an equal cents per kilowatt hour allocation, and; proposed changes to the FMC rate structure are approved.

We also establish a transition mechanism to phase-in implementation of the PCA in conjunction with a future evaluation by the Commission of the Company's normalized costs and authorized return on equity and whether it should be adjusted to reflect the risk that will be displaced by implementation of a PCA.

SUMMARY

Because Idaho Power is an electric utility that relies predominantly upon hydroelectric generation, the Company's actual cost of generating electricity (power supply costs) can vary dramatically from year to year as stream flows change. When stream flows are low, the Company must rely increasingly upon coal-fired and other resources that are more costly than hydro to operate.

The Company's present rates are established through a process called "normalization" in which power supply costs are calculated by averaging modeled power supply costs produced by multiple historical hydro conditions. Under normalization, Idaho Power's rates are set based on the averages and are not adjusted annually to account for the difference between actual stream flow conditions and normalized conditions. The Company contends that during extended periods of low water it suffers earnings instability and cash flow problems because it is not able to recover its increased net power supply costs which can vary from year to year by more than $100 million. Conversely, in years of abundant stream flows with correspondingly low power supply costs, Idaho Power, under the current system, retains savings for itself and does not share them with ratepayers. Stated simply, the purpose of Idaho Power's Application in this case is to establish a permanent mechanism that will adjust rates annually to reflect variations in power supply costs. Due to the unique nature of the Company's service to FMC and the impact a PCA would have on Idaho Power's decisions on when and how to interrupt FMC's load, Idaho Power has also proposed restructuring the relationship between FMC's primary and secondary rates in a manner that is revenue neutral.

An evidentiary hearing was conducted in this matter on March 9-11, 1993. Every party to this case supports the general concept of a PCA for Idaho Power. In addition to the threshold question of whether to implement a PCA, numerous policy and technical issues were raised regarding the precise form that the PCA should take. Not every party stated a position on every issue. Silence by a party on any given issue was not construed as concurrence with the position of any other party on that issue.

THE ISSUES

Should a PCA Be Adopted?

Idaho Power

Idaho Power argues that the current system of normalization does not work. During extended periods of low water the Company's earnings can suffer significantly, resulting in cash flow problems which place constraints on the Company's operations and maintenance and capital expenditures. The low earnings during extended periods of drought, Idaho Power argues, also place the

Company at risk of a poor rating by financial analysts, thereby increasing the cost to Idaho Power when it must enter the capital markets for financing.

The Company asserts that the best means of addressing the variability in its power supply costs is to replace normalization with a PCA that compensates for that variability. This would greatly stabilize Idaho Power's earnings. Ratepayers would also benefit from such a mechanism when stream flows are high and rates are adjusted downward. For the purposes of this case, Idaho Power defines PCA costs (which are largely influenced by stream flows) as: Fuel costs + non-firm purchases + cogeneration, small power production (CSPP) costs - non-firm revenue - FMC secondary revenue.

Idaho Power cites two additional benefits to the adoption of a PCA: resolving the controversy over the number of water years to use in normalizing power supply costs and eliminating the need for future filings of CSPP tracker cases. These issues are further discussed elsewhere in this Order.

<u>All Other Parties</u>

All of the other parties to this proceeding recommend the adoption of a PCA for Idaho Power.

FINDINGS

The current system of power supply cost normalization (based upon multiple hydro conditions) was proposed by Idaho Power in 1981 and approved by this Commission in Case No. U-1006-185, over a decade ago. At the time, both the Company and the Commission believed that the normalization system adopted would make the Company whole in the long run. Certainly no party to that proceeding anticipated the severe drought years that were to follow. It is now apparent that while normalization does make the Company whole over a period of years, during periods of extended drought the Company suffers from significant earnings instability and cash-flow problems. The Company, for example, is forced to curtail its plans for maintenance and expansion of plant and services. Ratepayers do not benefit from a utility that is financially impaired in this manner.

Since we adopted the current system of normalization, Idaho Power has requested and received two separate drought related surcharges. The first was issued in Case No. IPC-E-88-2, in 1988, and the second in Case No. IPC-E-92-10, in 1992. We find that the current system of normalizing power supply costs and granting Idaho Power a surcharge during drought years is defective because it is unpredictable and ratepayers do not receive any rate reduction during high water years.

Presently, Idaho Power must take the initiative to seek a drought related surcharge when it believes its financial condition has deteriorated to the point where additional rate relief is critical. In Order No. 24308, issued in Case No. IPC-E-92-10, we granted Idaho Power a $15 million surcharge on the basis of the Company's overall financial condition. The Company requested more. At least one intervenor argued that the Company deserved nothing.

A rate adjustment mechanism based upon specific criteria eliminates the need for the Commission to engage in subjective evaluations as to the overall financial need of Idaho Power on an infrequent basis. A PCA will provide consistency and predictability.

Of equal importance, while ratepayers are subject to a surcharge in poor years, they currently do not receive any reduction in rates in high water years leading most customer groups to believe that the current system works to their disadvantage when hydro conditions are good. The PCA we adopt addresses this concern and will produce consumer benefit in the form of lower rates during years of favorable stream flows.

We find, therefore, that it is in the best interests of ratepayers and shareholders alike to adopt a PCA for Idaho Power. We emphasize, however, that our decision is limited to the unique circumstances of Idaho Power's highly variable power supply costs. While it is difficult for a normalization process to capture these large annual changes, we continue to believe that normalization is a valuable ratemaking methodology for other types of expenses and revenues. Nothing in this Order should be construed to the contrary.

Forecast vs. Deferred PCA

Every PCA proposed in this case falls generally into one of two categories: forecast of projected power supply costs, or deferred accounting of past power supply costs. Under a forecast-based PCA, power supply costs for the coming year are projected and compared with a normalized base level. Rates are then adjusted for the year to reflect the difference. If, at the end of the year, actual power supply costs vary from forecasted, then under every PCA proposed in this case, a true-up would be added to or subtracted from the following year's rate adjustment to account for that difference.

Under a deferred accounting methodology, differences between normal costs and actual costs are deferred into a balancing account until a specified amount accumulates or for a specified time period after which rate adjustments are made.

Idaho Power

Idaho Power proposes a PCA based upon a forecast of the April through July Brownlee volume inflow provided by the National Weather Service's Northwest River Forecast Center located in Portland, Oregon. Using forecasted Brownlee inflow, the Company has developed an equation, using a linear regression technique, relating inflows at Brownlee Reservoir to modeled power supply costs. Idaho Power would input into its equation an estimated inflow at Brownlee to project power supply costs for the coming 12-month period. The forecasted costs are then compared with a normalized base cost. The difference is incorporated into all firm retail customers' rates for the following 12-month period. At the end of the 12-month period, the difference between forecasted power supply costs and power supply costs actually incurred is calculated. This difference is either recovered or refunded by factoring it into customer rate adjustments for the following 12-month period.

Idaho Power originally proposed using the linear regression technique to correlate forecasted Brownlee inflows with estimated power supply costs. The Company later agreed to use Staff witness Eastlake's logarithmic method as discussed below.

Commercial Utility Customers (CUC)

CUC recommends a forecast-based PCA. CUC believes that a forecast provides a better matching of power supply costs with the time period in which they are incurred. CUC contends, however, that forecasted Brownlee inflow is not an accurate predictor of net power supply expenses. Idaho Power's forecasting method, according to CUC, should be able to explain in excess of 80 or 90% of the variation in power supply costs. The model, however, only explains 66% of the variation. In spite of CUC's concerns over the degree of Idaho Power's forecasting accuracy, CUC's witness David Eberle testified that he could not design a regression that would improve forecasting accuracy. In fact, Mr. Eberle testified that he had not tried to improve the accuracy of Idaho Power's regression technique.

Eberle pointed out that the National Weather Service's forecast inflows for Brownlee can vary significantly from actual inflows. Because Idaho Power relies upon this single variable as the benchmark for forecasting power supply costs, Eberle contends, there is a potential for rate instability. Eberle attempts to address this problem by proposing a "deadband" which will be discussed below. CUC does not propose a specific forecast method other than that recommended by Idaho Power.

Idaho Irrigation Pumpers Association (Irrigators)

The Irrigators recommend a forecast-based PCA that is different from the Company's proposal. The Irrigators' witness, Anthony Yankel, argues that the forecast should not attempt to predict 12 months of usage and cost but should include three months of actual information and nine months of estimated data to be essentially based upon a calendar year. Mr. Yankel contends that such a method explains 84% of the variations in power supply costs. Rate adjustments based on his method, however, would not coincide with the forecast period.

Federal Executive Agencies (FEA)

The FEA recommends adoption of Idaho Power's forecast proposal.

Industrial Customers of Idaho Power (ICIP)

ICIP recommends adoption of a deferred accounting PCA. ICIP's witness, Donald Schoenbeck, argues that Idaho Power's proposed forecast method does not predict actual power supply costs with an acceptable degree of accuracy. The Company's proposal results in adjustments to rates that vary significantly from year-to-year without constraints or limitations. This rate instability is unacceptable to ICIP. ICIP recommends not adjusting rates until actual power supply costs have deviated from a normalized base level by plus or minus $22.6 million for the Idaho jurisdiction. When this "trigger" point is reached, the entire balance in the deferral account would be passed through to ratepayers as a rate adjustment.

Commission Staff

The Commission Staff presented the testimony of witnesses Bill Eastlake and Keith Hessing. Mr. Eastlake testified as to what he considered to be an improved forecast-based PCA. Eastlake argues that Idaho Power's forecast method is a poor predictor of power supply costs. He recommends modifying Idaho Power's proposal by substituting a linear regression technique which uses the natural logarithm of stream flows for the linear regression technique the Company proposed in its Application. According to Eastlake, a logarithmic fit produces a higher degree of accuracy in forecasting power supply costs. The Company accepted Mr. Eastlake's use of a log fit regression as an improvement to its forecast methodology.

Mr. Hessing advocates a deferred accounting PCA. This is Staff's primary recommendation. Under Hessing's method, 50% of the difference between actual and normalized power supply costs would be placed into a deferral account. When that account balance reached plus or minus $11.9 million for the Idaho jurisdiction, the accumulation would be passed through to ratepayers with a rate adjustment.

FINDINGS

We find that a forecast-based PCA with a true-up is most appropriate for Idaho Power. A forecast most closely matches costs to the time period in which they are incurred. This sends the more appropriate price signals to ratepayers. Under either of the deferred accounting PCA's proposed in this case, it would be possible that rates would not be adjusted until years after the costs which caused that adjustment had been incurred. A PCA based on a forecast does not suffer as greatly from this defect.

Ratepayers in Idaho Power's service territory are aware of changing stream flow conditions and understand the impact they have on the cost of generating electricity. A PCA that adjusts rates to reflect projected stream flows for the coming year should be understandable to ratepayers and send short-term price signals to ratepayers more reflective of actual conditions than rates set using normalization.

The ability of a forecast-based PCA to send correct price signals and to appropriately time the recovery of costs depends, of course, upon the accuracy of the forecast. We share the concerns of the Staff and ICIP that if Idaho Power's forecast is seriously in error, it may result in a true-up larger than the primary adjustment. This impairs the ability of the PCA to send proper price signals. It also diminishes rate stability. We accept Idaho Power's agreement to use a logarithmic method for correlating forecasted Brownlee inflows with estimated power supply costs. Other provisions of this Order with respect to sharing, interest computation, and recognition of load changes will also mitigate against the predictive inaccuracy of the model. We intend to monitor the results of Idaho Power's PCA over the coming years. If it appears that the degree of accuracy is inadequate, we will revisit the issue.

Finally, we find that a forecast-based PCA that trues-up to actual, as proposed by Idaho Power, eliminates the possibility of the Company over-recovering its power supply costs.

Sharing

Two forms of sharing were proposed in this case: "deadbands" and "percentage splits." Essentially, "sharing" is any method that provides for something less than a 100% pass-through of actual power supply costs to ratepayers.

<u>Idaho Power</u>

Idaho Power proposes to pass 100% of actual power supply costs through to ratepayers. Although the Company's proposal uses a base of normalized power supply costs in calculating the annual adjustment to rates at the beginning of each year, that base becomes irrelevant when the Company trues-up to actual costs at the end of each year.

Idaho Power cites two specific benefits to its proposal. First, a 100% pass-through of costs maximizes earnings stability for the Company. Idaho Power asserts that this is an important benchmark used by financial rating analysts and is critical to the Company's continuing financial health.

Second, Idaho Power argues that by eliminating the importance of establishing a normalized base for power supply costs, the Commission can resolve, once and for all, the contentious issue of how many water years to use in calculating that base.

FEA

The FEA supports Idaho Power's proposal to pass 100% of power supply costs through to ratepayers.

Irrigators

The Irrigators do not recommend passing 100% of power supply costs through to ratepayers. The Irrigators assert that allowing a 100% pass-through of costs effectively eliminates any incentive Idaho Power has to minimize those costs. Under the current system, the power supply cost component of base rates is established on normalized stream flow conditions. In any given year, the Company recovers this normalized level of power supply costs while actual power supply costs vary substantially. If the Company is efficient in minimizing these costs, it is allowed to retain the financial benefits. This incentive, the Irrigators argue, works to the benefit of all ratepayers when Idaho Power comes before the Commission in a general rate case and normalized power supply costs are again established on a presumably lower basis due to the Company's efforts to minimize costs.

The Irrigators' witness Yankel proposes a 100% recovery of all forecasted costs but less than a dollar-for-dollar recovery of deviations between actual and forecasted costs, i.e., a percentage split. Yankel recommends that the Company be allowed to pass 100% of all CSPP, fuel and purchased power costs used to supply firm load through to ratepayers. He defines "firm load" as the cost of supplying the firm system load excluding FMC's load.

Yankel recommends that all CSPP costs, fuel costs and purchased power costs not used to supply firm system sales customers' requirements would be recovered at 100% of the forecasted level but only 80% of the difference between forecasted and actual results. He recommends similar treatment for all non-firm and/or non-system revenues including FMC and all off-system sales.

CUC

CUC advocates the use of a deadband centered around one standard deviation in predicted Brownlee inflows. Under this method, differences in power supply costs resulting from variations of one standard deviation or less for forecasted Brownlee inflows would not be passed through to ratepayers. The Company would either have to absorb the increased costs or would retain the benefits of decreased costs within this deadband.

CUC's proposal would require that a normalized base of power supply costs be established and the issue of water years would remain alive. CUC's witness Eberle argues, however, that a deadband would provide two important benefits. First, as the Irrigators contend, the Company would be provided with the incentive to minimize its power supply costs if it is not allowed to pass 100% of those costs through to ratepayers.

Second, Eberle asserts that a deadband will maintain a certain degree of rate stability because power supply costs must vary by more than plus or minus approximately $29 million (one standard deviation) before rates are adjusted. CUC argues that rate stability is an important consideration for small businesses that must attempt to predict electricity costs for the coming year when preparing their annual budgets.

CUC also proposes placing a cap of 5% of Idaho Power's retail revenues on the amount of rate adjustment that can be in effect at any one time. This is not a true form of sharing because variations in power supply costs that exceed the 5% limitation will be deferred and factored into rates at a later time. It is another means of providing rate stability.

ICIP

As stated earlier, ICIP recommends deferring the difference between actual and normalized power supply costs into an account until the balance reaches plus or minus $22.6 million for the Idaho jurisdiction at which time the balance in the account is passed through to ratepayers in the form of an increase or decrease in rates. This method has been referred to as a "bucket." When power supply costs that vary from normalized reach a trigger point, the bucket, i.e., the deferral account, is emptied and passed through to ratepayers in the form of a rate adjustment.

A deadband, to the contrary, is a form of sharing. Differences in power supply costs between actual and normalized are never passed through to ratepayers.

ICIP, however, does recommend sharing in the form of a percentage split. It proposes that only 90% of the differences between actual and normalized power supply costs be collected in the deferral account except that 100% of CSPP costs would be included.

ICIP argues that it is inappropriate to shift the entire risk of variations in power supply costs to ratepayers; doing so would completely eliminate any incentive the Company has to minimize its costs. ICIP also asserts that its proposal will provide more rate stability than the Company's proposal.

Finally, ICIP also proposes a 5% cap on rate adjustments, similar to that proposed by CUC.

<u>Staff</u>

Like the ICIP, Staff proposes a deferral "bucket", but in the amount of plus or minus $11.9 million for the Idaho jurisdiction. Staff also proposes a 50-50 percentage split, including CSPP costs. Under Staff's proposal, 50% of the difference between actual and normalized power supply costs, including CSPP, would be deferred into an account. When that account balance reached a plus or minus $11.9 million, the entire amount would be passed through to ratepayers in the form of a rate adjustment. Staff cites the same rationale for its proposed sharing as stated by other parties: retaining an economic incentive for the Company to minimize costs and maintaining rate stability.

Staff recommends a different form of limitation on the amount of rate adjustment to be allowed during a given time period. Staff proposes that no more than two rate decreases or two rate increases be allowed to go into effect at any one point in time. To the extent that more than two similar rate adjustments would otherwise go into effect, Staff recommends deferring the excess adjustment until one of the first two drops off. Again, this is not a form of sharing.

Staff witness Eastlake recommends that, if a forecast basis is used, a deadband of 3.1 million acre feet (measured at Brownlee Reservoir) to 6.4 million acre feet be adopted.

FINDINGS

The power cost adjustment mechanism we adopt today is a significant departure from the current system in which shareholders bear the risk or receive the benefit that in any one year power supply costs will be significantly greater or less than the amount of those costs being recovered in normalized rates during that year. While one of our objectives is to help stabilize the Company's earnings, the PCA proposed by Idaho Power would result in a complete shifting of this risk from shareholders to ratepayers. We are concerned that an immediate and complete shifting of risk will compromise, to an unacceptable degree, the equally important goals of providing economic incentives for efficiency and avoidance of rate shock.

Efficiency Incentive

While we find that power supply costs are largely beyond the control of Idaho Power, there was ample evidence presented establishing that the Company's management does have some discretion in how and when to incur those costs. If we were to allow 100% of those costs to be passed through to ratepayers, the Company would not have the same degree of incentive to minimize those costs as it would if some degree of sharing is retained.

Idaho Power witness Gale testified that a 90-10 percentage split would provide the same cost minimization incentive to the Company as a 50-50 split. We find that a 90-10 sharing provides the Company with a sufficient incentive to efficiently manage its power supply costs. Furthermore, it is a better reflection of the degree to which Idaho Power can influence those costs. We find that, after the initial phase-in period (discussed below) allowing Idaho Power to recover 90% of its net power supply costs through a PCA will achieve the goal of earnings stability while still providing an adequate incentive for efficiency.

Rate Stability

As noted above, many of the parties expressed concern about the frequent and significant rate changes that would occur under the Company's proposed PCA, and these parties propose various rate stability mechanisms. Concerns about rate stability are legitimate. The dilemma, though, for the

Commission is that the goals of earnings stability for the Company and rate stability for the customers are in direct conflict with each other. To the extent we promote one goal, we necessarily impinge on the other.

After reviewing the various rate stability proposals, we find that the most reasonable solution is, rather than now adopting a specific rate stability mechanism, we reserve the right to examine proposed rate changes occurring in any one year and to impose different recovery methods if the proposed rate changes appear to seriously impair rate stability. As we gain experience with the PCA, specific rate stability limits may be further examined.

Idaho Power represented during the hearing that it was willing to accommodate the Commission's desire to ameliorate the "rate shock" that could result during periods of very low water. We accept this offer but note that the goal of rate stability is of such importance that we would have imposed a similar requirement even in the absence of the Company's acquiescence. For the purpose of giving a degree of specificity to this rate stability goal, we require the following: if forecasted increases above normalized power supply costs in any given year are predicted to exceed 7% of the Company's normalized base revenues for the Idaho jurisdiction, then Idaho Power is instructed to make a filing with the Commission for the purpose of determining whether a means to defer a percentage of that year's power supply cost recovery should be investigated. This notification requirement also applies if PCA rate changes for a current year, when combined with true-up adjustments for a previous year, would increase rates in excess of 7% of normalized base revenues.

We have chosen this 7% notification limit based upon historic variations in power supply costs. This limit will allow the PCA to operate uninterrupted in most years but will guard against extreme rate shock in very poor water years. This method will also allow the Commission to take into account the accumulative effects, if any, of true-up recovery for prior year adjustments.

<u>Risk Shifting</u>

As noted above, implementation of this PCA constitutes a significant reallocation of the risk that power supply costs will be greater than normal in any one year. Under normalization, most of this risk is placed on the Company and its shareholders. Under this PCA, however, the risk is being shifted from shareholders to ratepayers. A PCA thus reduces the business and financial risk of Idaho Power.

The Company's chief financial officer confirmed this risk-shifting effect and noted that the financial community would view Idaho Power more favorably from a risk point of view if a PCA was adopted. One analyst, for example, has written:

> Investors will and do recognize the normalized earnings power of IDA but apply some discount for volatility. We believe that if management were able to secure a regulatory mechanism in Idaho which smoothed out earnings over both the good and bad hydro years, investors could not justify discounting normalized earnings because the extreme earnings volatility would be eliminated or at least moderated.

Prefiled Direct Testimony of Lamont Keen pages 12-13.

In public utility rate setting, a utility is compensated for assuming various business and financial risks through the authorized return on equity established by the utility's regulatory commission. In general, as the utility takes on more business or financial risk, its regulatory commission approves a higher return on equity. The converse is also true; less assumed risk translates into a lower authorized return on equity.

Before Idaho Power's ratepayers are asked to assume the risk of year-to-year hydro fluctuations, they are entitled to the assurance that the Commission has examined the allowed return on equity to ensure that it correctly reflects the new level of reduced risk resulting from adoption of a PCA. Therefore, until such time as the Company files a general rate proceeding or other proceeding in which its rate of return may be examined, Idaho Power may recover 60% of the variation between base case net power supply costs and actual power supply costs through the PCA mechanism we approve today. The remaining 40% of power supply costs will be recovered through existing normalized rates. Upon completion of any proceeding in which we reexamine Idaho Power's normalized costs and authorized return, the Commission will enter its Order permitting Idaho Power to recover 90% of power supply costs through the PCA.

This 60-40 sharing during a transition period represents a fair balancing of shareholder and ratepayer interests. The Company receives the opportunity to recover the majority of the variation in its power supply costs automatically through the PCA and shareholders receive the assurance that after the transition period, 90% of that variation in costs will be recovered through the PCA. Ratepayers receive the assurance that before the PCA is fully implemented, the base rates of the Company will be examined to ensure that they correctly reflect the new level of reduced risk associated with a fully phased-in PCA.

Treatment of CSPP

Idaho Power

The Company proposes to include 100% of the cost of purchasing CSPP resources in the PCA. Although there is a capacity component to CSPP, the Company argues that these resources are distinct because Idaho Power is legally obligated to acquire them under the Public Utilities Regulatory Policies Act of 1978 (PURPA).

Currently, the Commission is allowing these costs to be accumulated and deferred, with interest, for recovery until a general rate case or CSPP tracker proceeding.

Staff

Staff argues that when Idaho Power first began acquiring CSPP resources under PURPA, the Company was in a state of energy surplus. Because Idaho Power was legally obligated to purchase energy it did not need, Staff contends, it was equitable to allow the Company to defer all of those costs (less a credit for revenues obtained in the resale of the electricity purchased) for later recovery. Staff argues that Idaho Power is quickly approaching load resource balance and now relies upon CSPP to serve firm system load. Staff proposes, therefore, to treat CSPP costs just like any other purchased power cost. Base costs would have a CSPP component, and on a monthly basis, 50% of the differences between the base and actual CSPP costs would be deferred and accumulate toward triggering a rate adjustment.

ICIP, Irrigators and FEA

All three of these parties recommend that 100% of the differences between forecasted and actual CSPP costs be passed through to ratepayers.

FINDINGS

We agree with Staff that CSPP has taken on added importance for the Company as we approach load resource balance. It may become necessary to reconsider our treatment of these costs at a future time. For now, however, we are still committed to allowing the Company a 100% recovery of a resource that it is forced to acquire under federal law. Including CSPP costs in the PCA is a more consistent and predictable procedure than is currently in place. We find, therefore, that the Company will be allowed to include 100% of CSPP costs in the PCA. Like any other PCA cost, it will be trued-up to actual expense.

Rate Allocation

Idaho Power

Idaho Power proposes an equal cents per kwh rate allocation. According to Idaho Power witness Rick Gale, power supply costs are overwhelmingly variable cost driven. The cost components that are identified in cost of service studies are primarily allocated by energy. In addition, the price signal given on the energy rate is the price the customer can respond to the quickest.

Gale asserts that differences in line losses between customer classes are already factored into Idaho Power's base rates and are, therefore, recognized.

ICIP

Of the other parties that took a position on this issue, ICIP was the only one to recommend a uniform percentage rate allocation. ICIP contends that the Company's proposed equal cents per kwh hour allocation is not cost based and exacerbates interclass rate inequities.

ICIP witness Schoenbeck argues that an equal cents per kilowatt hour allocation is not cost based for three reasons: it does not reflect seasonal variations in Idaho Power's power supply costs, it does not account for differences in line losses between customer classes, and it does not account for the capacity component of power supply costs.

Schoenbeck did not explain how a uniform percentage allocation would reflect seasonal variations in Idaho Power's power supply costs. He also did not indicate what the net revenue requirement impact to the industrial class of customers would be because of the alleged failure of the equal cents per kwh allocation method to account for seasonal variations in rates.

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ICIP did not offer any specific evidence regarding what the total net revenue requirement impact on the industrial class of customers would be because of the equal cents per kwh allocation method's failure to account for line losses.

Finally, Mr. Schoenbeck could not state exactly what percentage of total power supply costs are capacity related.

<u>CUC</u>

CUC recommends an equal cents per kwh allocation contending that it is more cost based and equitable than the uniform percentage method. According to CUC witness Eberle, the percentage of purchased power and fuel costs that can be allocated to demand is less than 4%. The percentage of revenues from off-system and FMC secondary sales is less than 15%.

Eberle disputes ICIP's contention that an equal cents per kwh allocation exacerbates interclass rate inequities. He contends that Schedule 9 customers (small commercial) currently pay rates that exceed the relevant cost of service. According to Eberle, a uniform percentage rate change exacerbates this situation rather than preserving interclass cost relationships.

Eberle points that neither the equal cents per kwh nor the uniform percentage allocation method addresses the seasonal variations in Idaho Power's power supply costs.

<u>Commission Staff</u>

The Commission Staff recommends an equal cents per kwh allocation which, Staff contends, is more cost based than a uniform percentage allocation. According to Staff, the percentage of net power supply costs that are capacity related is quite small. In addition, neither the uniform percentage nor the equal cents per kwh allocation address the seasonal variations in Idaho Power's power supply costs. Finally, the impact of the alleged failure to account for line losses between customer classes is so small that it is negligible. Staff contends that to apply PCA rate adjustments on a uniform percentage basis would contradict cost-of-service principles.

FINDINGS

In Case Nos. IPC-E-88-2 and IPC-E-92-10, we chose to allocate Idaho Power's requested surcharge on a uniform percentage basis. Those two cases differ entirely from the one at hand. Here, we are establishing a permanent mechanism that will not only increase rates when stream flows are low but will also decrease rates when stream flows are high. Thus, under an equal cents per kwh allocation, energy intensive customers will pay a relatively higher percentage of power supply costs during low water years and a relatively lower percentage during good years. This symmetry provides a fairness that could not be achieved with an equal cents per kwh allocation in a surcharge-only case.

Power supply costs are predominantly energy related. The supposed defects of an equal cents allocation cited by ICIP are either insignificant or non-existent. A uniform percentage allocation is not even remotely cost based. It is true that allocating costs according to energy, demand or customer components will have a varying effect on customer classes, according to their energy usage characteristics. This is simply the nature of cost-based ratemaking. To the extent that interclass rate inequities presently exist, a uniform percentage allocation can actually exacerbate those inequities.

We find that equal cents per kwh is a more cost based, logical and equitable method of allocating power supply costs under a PCA.

Firm Retail Load Changes

Staff

Staff argues that the power supply costs of serving differences between normal and actual firm retail load should be factored out of the PCA. Differences from normalized firm retail load are caused by factors such as changes in load and abnormal weather. Staff contends that some differences in power supply costs are caused by changes in load and that the associated differences in power supply costs are not appropriate for PCA treatment. If the Company is allowed to increase rates to account for the power supply costs of serving additional load and to recover base rates which also include power supply costs, the Company is double recovering those costs. Fuel costs (a component of net power supply costs) are first paid when load growth customers pay their electric bills at the end of the month. They are again paid in the following year after the Company captures them in its year-end true-up and spreads them to ratepayers.

Staff proposes to adjust actual power supply costs to normalized load levels. This is done by multiplying the difference between normalized and actual loads by 16.84 mills per kwh, which is the average of the fuel costs between

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Valmy and Boardman, and then subtracting this result from actual power supply costs. Staff believes that 16.84 mills per kwh approximates fuel costs associated with changes in load that should be adjusted out of a PCA. Such adjustments are symmetrical around the Company's normalized load. Equal differences above or below the normalized load contribute equally to reduce or increase PCA rate adjustments.

Staff contends that under Idaho Power's proposal, which contains no adjustment for changes in load, the PCA would serve as a surrogate for a general rate case. The Company would not have as much of a need to file for a general rate increase if it is allowed to offset the costs of constructing new plant with fuel costs double recovered in its PCA.

Idaho Power

Idaho Power argues that Staff assumes that the Company is capable of serving firm load growth at the cost of generating incremental energy. In fact, the Company asserts, new plant must be constructed to serve new load. Idaho Power witness Gale suggests that Staff fails to consider this in its analysis.

FINDINGS

We find that the net power supply costs associated with serving differences in load between normal and actual should be removed from the PCA. We adopt the method proposed by the Staff for making this adjustment; it was the only method proposed. We agree with Staff that Idaho Power's proposal unduly broadens the scope of this proceeding, which is simply to devise a mechanism for the recovery of power supply costs that include the sum of fuel costs, non-firm energy purchases and CSPP costs less revenues from non-firm energy sales and FMC secondary sales. Idaho Power's proposed PCA allows it to double recover fuel costs associated with load growth which, essentially, offsets the cost of constructing additional plant. We recognize and support the Company's right to recover costs associated with prudent plant additions. Our decision to not allow a PCA mechanism to recover costs to offset legitimate plant costs caused by load growth in no way prevents the Company from recovering these costs in traditional ratemaking proceedings. A PCA is not intended to replace the prudency review process inherent in a general rate case.

Interest on Deferrals

FEA

The FEA's witness Matthew Kahal recommends that interest be accrued on amounts being deferred to the next true-up for two reasons. First, unless interest is accrued, revenue over-recovered through the PCA provides the Company with cost-free capital until the annual true-up. Conversely, revenue under-recovered imposes a cost to the Company for which it is not otherwise reimbursed.

The second reason for including interest is that the amounts accrued are not entirely outside the control of the Company. If Idaho Power overstates its forecasted power supply costs, it essentially acquires cost-free capital at the ratepayers' expense. Thus, the absence of interest accruals provides Idaho Power with an incentive to overstate its power supply costs.

Kahal recommends the use of the bank prime rate.

Commission Staff

The Commission Staff suggests that if its deferred accounting PCA is adopted, then interest on deferrals is unnecessary because the credits should offset the debits. If, however, a forecast PCA is adopted, Staff recommends that interest be accrued because it believes that the Company's forecast methodology, on the whole, will overstate power supply costs thus providing it with an interest-free source of capital.

Idaho Power

The Company, in response to the proposals of other parties, has consented to the accrual of interest on PCA deferrals.

FINDINGS

All of the parties that took a position on this issue support the accrual of interest on PCA deferrals. If power supply cost forecasts were perfectly accurate there would, of course, be no need for accruing interest. To the extent that Idaho Power has control over the forecast of power supply costs, however,

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the accrual of interest acts as a safeguard and motivates the accuracy of those forecasts. We find that interest should be calculated and added to all amounts deferred for later true-up. We further find that an appropriate rate of interest is the interest applied to customer deposits held by the Company. This rate is defined and set forth in IDAPA 31.C.1.6.b. Essentially, it is the average interest rate for a one-year treasury bill. The Commission set the rate at 4% for 1993 in Order No. 24578 issued in Case Nos. 31.C-R-91-2 and 31.D-R-91-2. The rate can change from year to year.

EXCLUSION OF FIRM OFF-SYSTEM PURCHASES AND SALES

FEA

FEA witness Kahal suggests that the Commission should consider excluding long-term capacity purchases, including the capacity component of future cogeneration and small power production (CSPP) purchases, from recovery through the PCA for three reasons. First, allowing the Company to recover this resource through a PCA may bias its selection of least-cost resources in the future. Recovery through base rates for the cost of constructing new generating resources is a much more uncertain and time consuming proposition for the Company than simply entering into long-term capacity purchase agreements and passing the costs on to ratepayers through a PCA.

A second reason for excluding long-term capacity purchases from the PCA is the potential for the over-recovery of revenues. As firm load grows, the Company must commit to constructing new generation resources or to entering into long-term purchases. As noted above, cost recovery is different for the two. The Company's current base rates include a recovery of the fixed costs associated with Idaho Power's thermal and hydro plants. Base rates are set so that a certain number of cents for each kilowatt hour sold will cover the current fixed costs of Idaho Power's generation plant. As firm load grows, the total revenue recovered from that portion of base rates will increase above the level of fixed costs at the time rates were set. That increase in total revenue would pay for the fixed costs of additional production facilities required to meet new load if there were no increases in unit costs over the years. If all new production capacity is obtained from long-term purchases, however, and the associated capacity costs are recovered through the PCA, that additional revenue produced by base rates is retained by the Company.

The third reason has to do with the rate design implications of including demand related costs in an energy-based PCA. There is a greater capacity component to Company-owned generation resources than to long-term capacity purchases. Thus, the costs of the two resources will be allocated differently to customer classes under traditional cost-of-service principles.

Kahal suggests that one way of avoiding the foregoing problems is to exclude capacity costs associated with long-term purchases from the PCA. The FEA, however, suggests that the Commission defer a formal decision on this issue until a later time. FEA believes that the most critical consideration should be to implement a PCA as quickly as possible.

Staff

Staff agrees with the concerns expressed by the FEA regarding long-term capacity purchases. Staff contends that it is not feasible to separate the capacity and energy costs of CSPP resources. Thus, Staff recommends that, in the near term, CSPP capacity costs that would be captured in a PCA mechanism would be a small percentage of PCA costs and do not represent a significant impediment to establishing a PCA at this time. Staff proposes, therefore, to include all CSPP costs in the PCA for now.

With regard to future non-CSPP firm purchases, however, Staff proposes that they be entirely excluded from PCA treatment unless Idaho Power brings them before the Commission and the Commission approves appropriate PCA treatment. Staff recommends that revenue from firm off-system sales be included into the PCA to off-set the unavoidable capture of the costs in the PCA mechanism.

FINDINGS

We agree with FEA that any PCA that includes purchased power costs may motivate the Company to enter into long-term capacity purchases rather than invest in its own generation plant because the former would not require the Company to accept any risk and would bypass the least cost planning and prudency review processes currently in place.

Although Idaho Power currently does not have any non-CSPP capacity contracts, we find that it is appropriate to exclude any future non-CSPP firm purchases from the PCA unless the Company has first obtained Commission approval to include them.

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FMC'S Rates

Idaho Power

Idaho Power proposes increasing FMC's secondary rate (i.e., its rate service that is most interruptible). Currently, the variable cost of operating Valmy is slightly higher than FMC's secondary rate. This creates a dilemma for Idaho Power's system dispatchers in trying to decide whether to operate Valmy or interrupt FMC's secondary load in order to meet system load. Increasing FMC's secondary rate so that it is slightly higher than the variable operating cost of Valmy will result in the Company always choosing to operate Valmy before interrupting FMC. To retain reverse neutrality for FMC, Idaho Power proposes to offset this increase in FMC's secondary rate with a decrease in its primary rate. Primary service has more limited interruptibility and, for the purposes of discussion in this Order, can be characterized as nearly firm service.

Idaho Power contends that its solution maximizes revenues from FMC and satisfies the Company's contractual obligations while assisting the implementation of the PCA. The Company originally proposed implementing the changes to FMC's rates on May 1, 1993.

Staff

Staff supports the proposed FMC rate change. Staff notes that it is important for any portion of Company load that is not included in the PCA to not adversely affect other customers' PCA rates. Staff believes that Idaho Power's proposal accomplishes this objective.

Irrigators

Irrigators' witness Yankel suggests that it is counter-intuitive to price FMC's rate for primary service, which is essentially firm, lower than FMC's secondary or interruptible service. In spite of his concerns, Yankel admits that a specific remedy does not readily surface with respect to this counter-intuitiveness. He suggests that the matter be approached with caution.

FMC

FMC agrees with Idaho Power's proposal but recommends implementing the changes to its rates on April 1, 1993. FMC's primary reason for accelerating the implementation is that it may avoid or mitigate service interruptions to secondary should water conditions in April be significantly below normal. According to FMC, Idaho Power has been steadily interrupting FMC's secondary service throughout the winter and it is in everyone's best interest to husband the remaining contractual interruptions for use during the balance of the year. Early implementation of the proposed rate redesign, with its higher secondary rate, FMC argues, promotes this goal by making FMC secondary sales economically advantageous under a broader range of conditions. On the other hand, if adequate water conditions exist, the new rates offer a greater chance that FMC may be able to receive service above what might otherwise be possible at existing or newly-elected contract levels. In either case, FMC contends, the probabilities are that Idaho Power and its customers will benefit from increased PCA revenues.

FINDINGS

No party to this proceeding specifically opposed Idaho Power's proposal. We agree with the Irrigators that it is unusual to price what is nearly firm service below interruptible for a given customer. Idaho Power's proposal, however, is a reasonable solution to a problematic situation. We find the proposed changes to FMC's rates to be fair, just and reasonable. If, during the next general rate case, it appears that the new FMC pricing structure has caused an increase in the power supply costs of other ratepayers, we will take the necessary steps to revise FMC's rates in a manner that is revenue neutral with respect to the PCA.

No party, including the Company, opposed FMC's recommendation to implement the changes to its rates on April 1, 1993. We find that the changes to FMC's rates shall become effective April 1, 1993.

CONCLUSION

In this proceeding we have been required to balance and reconcile conflicting but valid objectives with respect to the proper design of a power cost adjustment mechanism. The PCA we adopt today will provide earnings stability for the Company in low water years and will provide ratepayer benefits in high water years through reduced rates. Recognizing that these benefits come at the expense of the goal of rate stability, we have included provisions to alleviate rate shock. We have also adopted measures to improve the accuracy of the forecast model. Notwithstanding this, we recognize that any forecast will have some degree of inaccuracy and we have included provisions to ameliorate these predictive inaccuracies. The transition mechanism we adopt assures ratepayers that the Company's base rates will be examined in conjunction with full implementation of the PCA.

Having carefully considered these competing policy objectives, and finding that the PCA we adopt today is generally within the range of options fully examined during our evidentiary hearing, we do not see a need for further comment through the vehicle of a proposed order. Accordingly, we decline the Company's invitation to issue a proposed rather than a final order.

Consistent with this Order, Idaho Power is authorized to file power cost adjustment surcharges or rebates to take effect on a day of its choosing in May or June 1993. The rate adjustment will be based upon the forecasted stream flows into Brownlee Reservoir and will recover 60% of the difference between base case power supply costs shown in the Company's Application and projected power supply costs using the logarithmic fit. During the 12 months that these rates are in effect, the Company will calculate 100% of the difference between projected power supply costs under the logarithmic fit and actual power supply costs adjusted for load charges. Sixty percent of this difference will then be booked into a deferred account for later true-up. Upon request of the Commission Staff, Idaho Power must report its monthly bookings to the Commission Staff.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over the Idaho Power Company and its Application in this case by virtue of Title 61, Idaho Code, and the Rules of Practice and Procedure of the Idaho Public Utilities Commission, IDAPA 31.A.

ORDER

IT IS THEREFORE ORDERED that the Application of Idaho Power Company for approval of a Power Cost Adjustment mechanism is hereby approved consistent with the terms and conditions set forth in the text of this Order.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in Case No. IPC-E-92-25 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in Case No. IPC-E-92-25. 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 29th day of March 1993.

Marsha H. Smith
MARSHA H. SMITH, PRESIDENT

DEAN J. MILLER, COMMISSIONER

Ralph Nelson
RALPH NELSON, COMMISSIONER

ATTEST:

Myrna J. Walters
MYRNA J. WALTERS
COMMISSION SECRETARY

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