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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS INTERIM AND BASE RATES AND CHARGES FOR ELECTRIC SERVICE.	)))))))))	**CASE NO. IPC-E-03-13**

DIRECT TESTIMONY OF KEITH HESSING

IDAHO PUBLIC UTILITIES COMMISSION

FEBRUARY 20, 2004

Q. Please state your name and business address for the record.

A. My name is Keith D. Hessing and my business address is 472 West Washington Street, Boise, Idaho.

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

A. I am employed by the Idaho Public Utilities Commission as a Public Utilities Engineer.

Q. What is your educational and experience background?

A. I am a Registered Professional Engineer in the State of Idaho. I received a Bachelor of Science Degree in Civil Engineering from the University of Idaho in 1974. Since then, I have worked six years with the Idaho Department of Water Resources, and two years with Morrison-Knudsen. I have been continuously employed at the Commission since August 1983.

As a member of the Commission Staff, my primary areas of responsibility have been electric utility power supply, revenue allocation and rate design.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses Jurisdictional Separations, Class Cost of Service, some Power Cost Adjustment (PCA) components and cloud seeding.

Q. Please summarize your testimony.

A. I recommend that the Commission accept the 12 coincident peak (12CP) Jurisdictional Separation Methodology proposed by the Company to allocate costs to the Idaho jurisdiction. This method applied to Staff's total Company Revenue Requirement results in an Idaho Jurisdictional Revenue Requirement of $498,758,249, which requires an average 3.06 percent rate increase to recover an additional $14,796,880 revenue requirement.

Staff accepts the weighted 12 coincident peak (W12CP) methodology proposed by the Company for the purpose of allocating costs to the Company's Idaho customer classes. Staff witness David Schunke proposes some non-cost based modifications to these cost of service results that become Staff's revenue allocation proposal.

I review the Company's Power Cost Adjustment (PCA) calculations that change as a result of a general rate case. Staff recommends that the Commission accept the Company's proposed changes except for the changes to the Expense Adjustment Rate for Growth. The Company proposes that the rate used to adjust actual power supply costs to remove the costs of load growth be the embedded cost of power supply which is 7.30 $/MWh. I propose that these changes from normal power supply costs occur at the marginal cost of power supply and, therefore, the marginal cost rate of 29.41 $/MWh should be used in the calculation.

Finally, my testimony discusses the Company's cloud seeding program including its effects on the PCA. I propose that there are questions regarding the program that remain unanswered and that need to be answered before the Commission can decide whether or not to accept the costs include in this case. My testimony includes some of those questions.

JURISDICTIONAL SEPARATIONS

Q. What are Jurisdictional Separations?

A. It is the process used to divide Idaho Power Company's annual costs among the jurisdictions it serves. In general the process identifies the Company's costs as related to the supply of energy, peak demand, or the number of customers. The costs are then divided to the Idaho, Oregon or Federal Energy Regulatory Commission (FERC) Jurisdictions based on each jurisdiction's proportional amount of each of these items. The FERC Jurisdiction consists of wholesale sales to other utilities. The Jurisdictional Separation process results in the Idaho Revenue Requirement, which is the amount of the Company's total normal annual Revenue Requirement that is caused by Idaho ratepayers and that must be recovered from Idaho ratepayers.

Q. What has changed since the Company's last general rate case that affects Jurisdictional Separations?

A. Big changes have occurred in the allocation factors. For example, the number of customers in Idaho and on the total System grew substantially since the last rate case, but the Idaho customer allocator only grew about 1 percent. The story is very different for the demand and energy allocators. Idaho's share of total Company peak demand grew approximately 8 percent and Idaho's share of total energy use grew approximately 9 percent. In all three cases Idaho's share of the total has increased. Because these are the characteristics used to divide or allocate costs among the jurisdictions, the Idaho Jurisdiction has become a larger share of the Company's total costs of providing service.

Q. Please explain in more detail the changes that have occurred in these allocators since the Company's last general rate case.

A. The addition of 100,000 new customers in Idaho did not substantially change the Idaho customer allocator because proportional growth occurred in the Company's other jurisdictions. The growth in the relative percentages of the energy and coincident peak demand allocators requires more explanation. Total Company energy consumption has declined and total Company peak demand has not increased as fast as peak demand in Idaho. There are a number of factors at play here. The large increase in customers increased Idaho Peak demand and energy requirements and Idaho Power lost its single largest customer, FMC/Astaris. Since Idaho Power's last general rate case, nearly all of its FERC Jurisdictional contract sales expired as originally designed so that the Company's resources could be fully utilized to supply its load growth. These expired contracts practically eliminated FERC Jurisdictional energy and peak demand. When Idaho's share of peak demand is calculated, the Idaho Jurisdiction becomes responsible for an additional 8 percent share of total Company demand-related costs. When Idaho's share of total energy is calculated, Idaho becomes responsible for an additional 9 percent of total Company energy-related costs, not only because Idaho's energy requirements increased but because total Company energy requirements decreased.

Q. Have you prepared an exhibit that shows how these allocation factors have changed since the Company's last general rate case?

A. Yes. Staff Exhibit No. 118 shows these changes. There are several different Energy, Demand and Customer Allocators used in the Jurisdictional

Separations Study. The exhibit includes one of each for illustrative purposes.

Q. Why has the Company not entered into firm contracts to sell the unused energy made available by the expiration of the FERC jurisdictional contracts?

A. Doing so would reduce Idaho's peak demand and energy allocators. However, the Company has also changed the load and water planning criteria in its Integrated Resource Plan. In response to high costs experienced by the Company and its customers in 2000 and 2001 when streamflows were low and market prices were extremely high, the Company now plans to meet its load during low water conditions with reduced reliance on market purchases. This change in planning criteria, coupled with new customer load growth, has all but eliminated excess energy available for new firm wholesale contracts.

Q. What happens to the uncommitted capacity that is being held in reserve to meet above normal load and/or below normal streamflow conditions?

A. In low water or high load conditions, the reserve capacity is available to the Company and its customers to meet load at a fixed price that will usually be below the cost of purchasing market power. In normal or above normal water conditions when the costs of generating with these resources is below market price, Idaho Power will sell the power and credit the revenues against expenses, which reduces customer rates. In this case, these benefits are captured in the power supply modeling process that establishes normal power supply costs included in base rates. On a year-by-year basis, deviations from base power supply costs are captured in the PCA.

Q. Does Staff agree with the Jurisdictional Separations process used by Idaho Power Company?

A. Yes. The Company used the same 12CP methodology that it has used for more than 20 years. It is appropriate for changes in Company costs and changes in jurisdictional use characteristics to change customer rates. However, without compelling reason, it is not appropriate to cause additional rate changes due simply to change in allocation methodology. In its analysis, Staff used the Company's methodology and jurisdictional allocators with Staff's proposed accounting adjustments to determine the Idaho Jurisdictional revenue requirement.

Q. What are the results of Staff's Jurisdictional Separations process?

A. Staff's cost of service results, revenue allocation to classes and rate designs are based on a total Idaho Jurisdiction revenue requirement initially determined to be $499,161,903 which is an increase of $15,200,534, and results in a 3.14 percent average increase in rates. After that initial determination, Staff auditors continued to examine specific items in the Company's revenue requirement, which ultimately reduced Staff's recommended Idaho Jurisdictional revenue requirement to $498,758,249, an increase of $14,796,880, or a 3.06 percent average rate increase. Because class cost of service studies, revenue allocations and rate designs involve complicated issues and analysis, it was necessary for the Staff members working on those issues to prepare their recommendations before the Staff auditors had concluded their analysis. Accordingly, Staff testimony on revenue allocation, cost of service and rate design are based on the initial Staff determination of the Company's Idaho Jurisdictional Revenue Requirement. Staff Exhibit No. 119 summarizes the results of Staff's jurisdictional separations study. Staff witness Schunke's testimony provides revenue allocation and rate design guidelines for the Commission's consideration that accommodate the reduced Staff revenue requirement proposal.

COST OF SERVICE

Q. What is a cost of service study?

A. A cost of service study divides the Idaho

Jurisdictional Revenue Requirement among the Company's various customer classes based on the cost-causing characteristics of the classes. The process is similar to the Jurisdictional Separations process. Allocators are developed for each customer class as percentages of the Idaho total for energy use, contributions to monthly coincident peak demand and numbers of customers. These allocators are then used to distribute the total Idaho Revenue Requirement to the various customer classes.

Q. What class cost of service methodology did the Company use?

A. The Company used substantially the same methodology that it has used in its last two general rate cases. The method is called the weighted 12 coincident peak (W12CP) method. For the allocation of production related costs, this method weights monthly coincident peak demands by the marginal cost of providing for those demands and averages the results with unweighted 12CP results. In months when the Company is not expecting a peak demand deficit, a zero weighting is applied. When seven of the months are weighted at zero, the allocators become the average of, what amounts to, a weighted 5CP methodology (the remaining five months of coincident peak demands) and an unweighted 12CP methodology.

The same method is used for the allocation of transmission related costs except on the transmission system there are nine months when the Company does not expect peak demand deficits. Therefore, only three weighted months are averaged with the 12CP numbers to obtain the proposed allocation factors. The major energy allocator is calculated based on monthly energy use weighted by the monthly marginal cost of energy. It is not averaged with other unweighted allocators.

Steam and Hydro production investment are classified as related to demand or related to energy based on an Idaho Jurisdictional Load Factor (the ratio of average use to peak use) of 55.26 percent. This means that 55.26 percent of these investments are allocated to customer classes based on energy use and the remaining amount is allocated based on peak demand.

Q. What has changed since the Company's last general rate case ten years ago that affects cost of service?

A. There have been many changes. A few of the changes are: the addition of 100,000 new customers, the loss of the FMC/Astaris load, the change in the Company's load and water planning criteria to a more conservative position, the deregulation of the wholesale electric market, and the change in the Company's load/resource characteristics from being energy constrained to capacity constrained.

Q. How might these changes affect cost of service results?

A. These changes affect the Company's underlying costs, the energy and capacity allocators applied to each customer class, and the marginal costs used to weight the allocators. Virtually everything that affects cost of service, except the basic methodology, has changed.

Q. Please describe the cost of service analysis performed by Staff.

A. Staff used the Company's W12CP methodology that has been accepted by the Commission in past proceedings. Staff also used the weighting factors and associated methodology proposed by the Company in recognition that capacity and energy are more costly to obtain in some months of the year. Staff recognizes that weighted months, some of which were weighted at zero, averaged with unweighted months, creates demand allocators that are more complex than those used in the past. Staff can accept the use of some zero weighted months because they are averaged with unweighted months and because they coincide with the months where no capacity constraint is expected. Staff Exhibit No. 120 shows the results of Staff's Cost of Service Study. In his testimony, Staff witness Schunke proposes a modified allocation of revenue requirement to customer classes that is not entirely based on cost of service results.

Q. Are unweighted and zero weighted months the same thing?

A. No. If the peak demand for a month is zero weighted, it is multiplied by zero and no value is included in the calculation of the weighted allocator for that month. If the peak demand for a month is unweighted, the actual coincident peak demand is used in the calculation of the allocator.

Q. How many cost of service studies did Staff perform?

A. Staff performed three cost of service studies. I have already described the first one which is the study recommended by Staff.

Q. What was the second study performed by Staff?

A. The second study is a weighted 12CP study with the weighted portion of the June allocator weighted at zero. The resulting ratio was averaged with the unweighted ratio to obtain the final allocators. The results of this study are shown on Staff Exhibit No. 121. The results of this study showed a decrease in the required increase for the irrigation class. The increase dropped from 47.2 percent to 44.5 percent.

Q. Please discuss Staff's third cost of service study.

A. The third study is a traditional unweighted 12CP study. The analysis removed all marginal cost demand and energy weightings used to calculate allocators. Weightings were removed in the calculation of production and transmission demand allocators and for the calculation of the energy allocator. Staff Exhibit No. 122 shows the results of the study. When all weightings were removed, which is the same as setting them at 1, the required increase in irrigation rates dropped again, this time to a 29.1 percent increase. Of course, any time the allocation drops for one class the other customer classes pick up the difference to produce the revenue required to cover the Idaho jurisdictional revenue requirement.

Q. Why did Staff perform the second and third studies?

A. The results of the Company's W12CP methodology require a substantial increase to bring the irrigation class to full cost of service, as might be expected with capacity and energy allocators more heavily weighted in summer months. Staff wanted to know how sensitive class allocations, especially irrigation class allocations, are to allocation factor changes. All three studies show the irrigation class requiring an increase far above any other class. Using the Company's methodology, as Staff did in its first study, the irrigation class would require an increase five times the next highest class increase.

Q. Please compare the effects of the unweighted 12CP methodology and the Company's W12CP methodology on the Residential customer class.

A. The results of the weighted 12CP study showed a 1.08 percent decrease for residential customers. Unweighted study results showed residential rates requiring a 1.71 percent increase. Given the residential customer's summer air conditioning load these results may seem inconsistent. However, a more detailed review of residential load data provides an explanation. The winter heating load is greater than the summer air conditioning load and January and February are zero weighted in the weighted 12CP production allocator. Also, all winter months are zero weighted in the weighted 12CP transmission allocator. The result is a relatively small effect on residential cost of service regardless of the allocator weightings used in the cost of service study.

Q. Why did Staff choose the Company's proposed cost of service methodology including its allocator weightings?

A. Staff believes that demand-related plant investments are driven by low hydro conditions and high loads in the critical peak months. It is the demand in these critical months when the system is capacity constrained that is most relevant in this analysis. Therefore, any analysis that does not weight the critical months more heavily than shoulder months does not correctly reflect forward-looking demand related costs. The Company's study gives heavier weighting to the five critical months of June, July, August, November and December. Therefore, Staff believes that the monthly weightings are justified and that the Company's cost of service methodology is reasonable.

THE POWER COST ADJUSTMENT (PCA) MECHANISM

Q. What is the PCA?

A. In general, the PCA is a rate adjustment mechanism that annually adjusts customer rates to recover or refund 90 percent of above or below normal load adjusted power supply costs. Each year the PCA is composed of a forecast or predicted component and a true up component.

Q. What PCA items does your testimony discuss?

A. Base power supply costs are established in a general rate case and those are discussed in Staff witness Rick Sterling's testimony. From the process that establishes base power supply costs comes the PCA forecast, which I will discuss. I will also discuss the load adjustment and some other components of the PCA calculation.

Q. How will the results of this rate case change the PCA?

A. The normalized power supply costs established in this proceeding will be included in the base rates of each customer class. The annual projection or forecast of power supply costs based on water conditions will also change. A change in base power supply costs will cause a recalculation of the predictive formula that relates April through July Brownlee inflow to Net Power Supply Costs. Each April this formula along with the National Weather Service runoff forecast is used to project net power supply costs for the coming year. Company witness Greg Said discusses this calculation in his direct testimony beginning at page 16. Page 19 of his testimony shows the Company-proposed forecast formula. Company Exhibit No. 35 shows the input data and regression results.

Q. Does Staff agree with the Company's calculation of the forecast formula?

A. Yes. Staff has not adjusted the Company's power supply model results in this case and proposes no changes in the forecast methodology other than exclusion of the FMC/Astaris adjustment proposed by Company witness Said (Direct Testimony, page 19, lines 17-24). Therefore, Staff calculates the same forecast formula as the Company.

Q. Does the Company propose to update other PCA computations?

A. Yes. Company Exhibit No. 36 shows four PCA computations that Company witness Said proposes to update. He updates "Normalized PCA Expenses" which is normalized power supply expense from the Aurora model plus normalized CSPP costs. The new number is $94,101,100 per year.

The Company updates the "Normalized Base PCA Rate" which is normalized PCA expenses divided by normalized system firm sales. The new rate is .7315 ¢/kWh.

Idaho Power also updates the "Idaho Jurisdictional Percentage" which is used to allocate abnormal power supply costs to Idaho. It is calculated by dividing normalized system firm load by Idaho jurisdictional firm load. The number is 94.1 percent.

Finally, the Company updates the "Expense Adjustment Rate for Growth" which is used to remove power supply cost increases associated with growth. Mr. Said calculates 13.98 $/MWh in the exhibit but uses a different rational to propose 7.30 $/MWh in his testimony.

Q. Is it appropriate to update these calculations in this general rate case?

A. Yes. These calculations are intended to be updated in a general rate case.

Q. Does Staff accept the results of the updated calculations for use in the PCA?

A. Staff accepts the Company's updated calculations as shown on Company Exhibit No. 36, except for the calculation of the Expense Adjustment Rate for Growth. Staff disagrees with the Company's rational for and calculation of this adjustment.

Q. Please discuss the Expense Adjustment Rate for Growth.

A. Such a discussion requires some basic PCA background. The PCA captures actual booked monthly power supply costs that are above or below the normal values established by the Commission and included in base rates. These differences from normal power supply costs result from abnormal streamflows, abnormal market prices, abnormal fuel prices, abnormal loads that may be caused by weather, buy-back programs, conservation, or load growth or loss. The Expense Adjustment Rate for Growth

(EARG) is aimed very specifically at the variable cost of power supply caused by changes in load. When load grows, the EARG is part of the mechanism that removes the above normal costs of power supply captured in PCA accounts that are associated with load growth. In essence this adjustment removes the power supply effects of load growth and leaves the effects of abnormal water conditions and market prices, which the PCA is designed to capture.

When loads are below normal, the EARG multiplier is part of the mechanism that prevents the Company from losing both the retail revenue and power supply cost savings that are credited back to customers through the PCA. Again, this adjustment removes from the PCA the power cost effects of the loss in load and leaves the effects of abnormal water and market prices in the PCA. When these adjustments are appropriately made using the correct multiplier, the Company neither over-collects nor under-collects power supply costs through the PCA when consumption is higher or lower than normal. The difference between power supply costs incurred to serve new customers and embedded power supply costs collected in rates must still be recovered in a general rate case just as it has been in the past. The PCA is left to capture predominantly power supply cost changes that result from abnormal water and market price conditions that would not be captured under the normal conditions assumed in a general rate case.

Q. You mentioned that the load adjustment mechanism works if the correct value is used as the Expense Adjustment Rate for Growth. What is the correct EARG value?

A. Power supply costs associated with load changes are captured in the PCA at the marginal cost level. Therefore, they must be removed at the marginal cost level. In Response No. 30 to the Second Production Request of the Idaho Irrigation Pumpers Association, Idaho Power identified the average annual marginal cost of energy as 27.01 $/MWh. This is Staff Exhibit No. 123. At the customer level, which includes 8.9% transmission and distribution losses, this becomes 29.41 $/MWh. I propose this as the appropriate EARG.

Q. What is the current EARG and where did it come from?

A. The current EARG is 16.84 $/MWh and it was established in Case No. IPC-E-92-25, the case that first established Idaho Power's PCA mechanism. Staff proposed 16.84 $/MWh in that case as a surrogate for the average marginal cost of power supply. It was calculated as the average of Boardman and Valmy fuel costs which at that time spanned the range of normal market prices. A surrogate for Idaho Power's marginal cost of power supply was proposed in that case because Staff did not have an operating power supply model that would allow it to incrementally adjust the load and calculate the marginal cost. In the Company's last general rate case, Case No. IPC-E-94-5, 16.22 $/MWh was calculated from an incremental power supply model run. No recommendation was made to change the 16.84 $/MWh EARG because the difference was small.

Q. What would be the result if the Commission adopted the Company's proposal to use the average power supply cost of 7.30 $/MWh for the Expense Adjustment Rate for Growth?

A. The difference between the actual marginal power supply costs of 29.41 $/MWh incurred to serve new customers and the 7.30 $/MWh embedded cost proposed by the Company would be collected from customers through the PCA and flowed through to Idaho Power Company shareholders. In other words the Company would collect power supply costs from new customers through base rates and collect 22.11 $/MWh (29.41 - 7.30) for new growth through a PCA surcharge. While the Company has argued that the revenue it receives from new customers does not cover all the incremental costs of adding them, the EARG proposed by the Company amounts to a windfall that more than recovers power supply costs. As I have previously stated, a general rate case, rather than the PCA, is the appropriate place to recover load growth related power supply costs. Therefore, Staff recommends that the Commission adopt its Expense Adjustment Rate for Growth of 29.41 $/MWh to eliminate the shareholder windfall and maintain the integrity of the PCA.

CLOUD SEEDING

Q. What is your understanding of the Company's cloud seeding program?

A. Several years ago, members of the Commission Staff, including myself, met with Idaho Power Company to discuss cloud seeding. At that time the Company was considering a pilot program to seed clouds in the upper Payette River drainage. The Company's goal was to provide more precipitation in that area in the form of snow that would melt during the summer and provide additional water to the Company's hydro facilities, allowing it to generate more electricity.

Part of the reason for the meeting had to do with the effects on the PCA of such a proposal. To the extent more water could be provided to generate more electricity, the value of that electricity would be captured by the PCA and substantially (90%) passed back to ratepayers. This would leave customers with the benefits and the Company's shareholders with the costs. The Company did not believe this distribution of costs and benefits to be fair. One alternative discussed was to allow the Company to include the costs of cloud seeding in the PCA so that customers would pay the costs and receive the benefits. Of course, if the benefits did not exceed the costs, the loss would be passed to customers through PCA rates.

Another alternative for cost recovery discussed at the meeting was that the Company simply begin the program and incur and book the costs. The next general rate case would then pick up a test year that included the costs, at which time they could be discussed and the Commission could choose to accept or reject them.

Rather than seeking recovery through the PCA, the Company has included cloud seeding costs for the 2003 test year in this case. Those costs include $897,448 in operation and maintenance expense (Account 536) and $214,600 in capital costs (Account 101).

Q. Does Staff have a position regarding the recovery of these costs in the current case?

A. The Company did not provide enough information in its filing for Staff to make a recommendation on the merits of cloud seeding. For example, the Company did not state whether the program has created measurable precipitation and, if so, how much. Without more information it is not possible to evaluate whether the cloud seeding costs were prudently incurred. If the Company does not provide additional information in this case, Staff recommends that all cloud seeding costs be removed.

Q. What information does Staff believe should be provided by the Company to allow an adequate opportunity to evaluate the requested cost recovery?

A. Given the experimental and somewhat controversial nature of cloud seeding programs and the sizable amount of money requested to be included in rates on an annual basis, Staff believes the Company should address the following issues:

1) What activities constituted the cloud seeding program in past years, including the test year, and what are the Company's cloud seeding plans for upcoming years?

2) What criteria will the Company use to determine the level of cloud seeding activity and expenditures necessary in any given year?

3) How does the Company evaluate whether cloud seeding works and that the benefits exceed the costs?

4) What would be the effect on the Company's

cloud seeding program if the Commission denied recovery of the costs requested in this case?

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.