Office of the Secretary
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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** **ORDER NO. 29505**

ISSUED MAY 25, 2004

BOISE, IDAHO

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SUMMARY

This is a final Order establishing the revenue requirement and rates for Idaho Power Company's (Idaho Power; Company) electric services in the State of Idaho. Idaho Power filed an Application on October 16, 2003 for authority to increase revenues by $85,561,910, an increase of 17.68%, effective November 15, 2003. The Company also requested that, if the Commission suspended the proposed effective date pursuant to *Idaho Code* § 61-622, interim rates be set effective November 15, 2003. In Order No. 29369 issued October 28, 2003, the Commission did suspend the proposed effective date of Idaho Power's new rates and charges, and subsequently considered the appropriateness of interim rates. In Order No. 29403 issued December 22, 2003, the Commission denied the Company's request for interim rates pending resolution of this case. By this Order, we authorize Idaho Power to increase its Idaho revenues by $25,327,533, or approximately 5.2%. As a result, electric base rates for specific classes will be increased on average by the following percentages: Residential 5.98%; Small General Service 5.97%; Large General Service 1.98%; Industrial 2.41%; and Irrigation 13.95%.

APPEARANCES

Following the filing of Idaho Power's Application, the Commission issued a Notice of Application and provided an opportunity for interested parties to file petitions to intervene. The Commission approved all petitions to intervene, resulting in the parties and their attorneys identified below:

Idaho Power Company:	Barton L. Kline Monica B. Moen
Commission Staff:	Lisa Nordstrom Weldon B. Stutzman Deputy Attorneys General

Industrial Customers of Idaho Power:	Peter J. Richardson Richardson & O'Leary
Idaho Irrigation Pumpers Association, Inc.:	Randall C. Budge Eric L. Olsen Racine, Olson, Nye, Budge Bailey, Chartered
The United States Department of Energy:	Lawrence A. Gollomp Assistant General Counsel
United Water Idaho Inc.:	Dean J. Miller McDevitt & Miller LLP
NW Energy Coalition:	William M. Eddie Advocates for the West
Micron Technology, Inc.:	Conley E. Ward Givens Pursley LLP
Community Action Partnership Association of Idaho:	Brad M. Purdy Attorney at Law
AARP:	Brad M. Purdy Attorney at Law
Kroger Company:	Michael L. Kurtz Kurt J. Boehm Boehm, Kurtz & Lowry

PROCEDURAL HISTORY

Idaho Power included in its Application a request for a uniform percentage increase of 4.16% on all existing rates contained in the Company's tariffs pending a hearing on its Application and a final Order. The Commission convened a hearing on November 13, 2003, to consider Idaho Power's request for interim rate relief. The proposed interim rates were based on the Company's assertion that it should be permitted to immediately add to rate base its investment in the Danskin Power Plant, investments it has made in the relicensing of hydro projects, adjustments to the Company's annual depreciation accounts, and an annual revenue requirement amount attributable to wholesale power supply contracts that have expired. The Commission determined that Idaho Power had not demonstrated the existence of a financial emergency to justify interim rate relief, and denied the Company's request for temporary rates in

Order No. 29403 issued December 22, 2003. The Commission convened a technical hearing on Idaho Power's Application commencing March 29, 2004 and concluding on April 5, 2004.

Prior to the filing of testimony, the Commission Staff in January 2004 conducted four workshops for interested customers to discuss the Company's Application and to answer questions. Formal hearings were held in Pocatello, Jerome, McCall, Payette and Boise in March 2004 to hear from members of the public on the issues presented in this case. Approximately 50 people attended the workshops and about 300 people attended the five hearings. Of those who attended, 88 people testified at the hearings. In Order No. 29436, the Commission also solicited written public comments regarding the Application to be filed on or before April 30, 2004. The Commission received more than 500 timely written comments from the public.

The Commission greatly appreciates the efforts ratepayers made to express their opinions regarding their electric rates and the proper regulatory oversight necessary to keep unreasonable expenses out of rates. We heard from many residential customers, the majority of whom opposed the Company's proposed increase in the service charge. Irrigation customers also contributed in large numbers to the record and expressed concern about the impact Idaho Power's proposed 25% increase would have on individual farms and the agricultural community. The Commission also heard from a large number of low-income and senior citizens, who asked us to consider current economic conditions before granting any rate increase. Numerous customers expressed concern about the lapse of a decade between rate cases, resulting in a large rate increase request and possible rate shock, rather than smaller incremental changes that would occur with more frequent rate cases.

With this background in mind, we now discuss the test year and revenue requirement issues presented in this case.

TEST YEAR

Idaho Power proposed a 2003 test year and initially provided actual account information for the first six months of 2003, and proposed to use projected account information for the second half of 2003. Tr. at 515, 1247. Because actual data would be available at the time of hearing, Staff and others argued that actual year-end figures should be used because they are more accurate than projected figures and better align costs and revenues. Tr. at 542, 1404-05, 1451-54, 2426-28. Idaho Power did provide actual numbers for the test year accounts showing year-end balances.

Based on the evidence in the record, the Commission finds use of a 2003 test year to be reasonable and appropriate in this case. We further find that the 2003 test year shall be updated with account information through December 2003 as discussed in greater detail below.

ADJUSTMENTS TO RATE BASE

Once a test year is selected, adjustments are made to test year accounts and rate base "to reflect known and measurable changes so that test year totals accurately reflect anticipated amounts for the future period when rates will be in effect." Order No. 25880 at 3. The Idaho Supreme Court has described "rate base" as "the utility's capital investment amount." *Industrial Customers of Idaho Power v. Idaho PUC*, 134 Idaho 285, 291, 1 P.3d 786, 792 (2000). Adjustments to test year accounts generally fall into three categories: 1) normalizing adjustments made for unusual occurrences, like one-time events or extreme weather conditions, so they do not unduly affect the test year; 2) annualizing adjustments made for events that occurred at some point in the test year to average their effect as if they had been in existence during the entire year; and 3) known and measurable adjustments made to include events that occur outside the test year but will continue in the future to affect Company income and expenses. Tr. at 554-55. This section of the Order addresses the proposed adjustments to rate base, followed by a discussion of adjustments to test year revenue and expenses.

Idaho Power projected a total electric system rate base for the 12 months ending December 31, 2003 to be $1,752,511,220, and made adjustments for known and measurable changes that reduced the rate base by $79,227,443, bringing the total proposed jurisdictional rate base (covering multiple jurisdictions) to $1,673,283,777. Exhibit 21. Idaho Power alleged it was entitled to an Idaho system rate base in the amount of $1,547,443,530. Staff and intervenors recommended additional adjustments to the rate base calculation, some of which were accepted by the Company. In this section of the Order we discuss the contested adjustments to rate base and determine the appropriate rate base for Idaho Power's operations in Idaho.

On the evidence presented and as discussed more particularly below, the Commission finds a total system rate base in the amount of $1,643,706,370 to be just and reasonable, of which the Idaho jurisdiction rate base is $1,519,924,799.

1. Update to Actuals.

As noted earlier, Idaho Power filed its case using actual account information for the first six months of the test year, and projected amounts for the second half of 2003. Tr. at 515,

1267. At the prehearing conference, Idaho Power agreed to provide Staff with the opportunity to review the actual data and present updated information on a supplemental basis if necessary before the Commission made a final decision. Tr. at 38, 1404. Staff proposed to use actual account information for the second half of the test year, as that information would be available prior to a final decision in this case. Tr. at 1404-05, 1451-54. Before updating with actual December figures, Staff witness Holm initially testified that the difference between Idaho Power's six months of projected data and its actual non-operating revenues, expenses and rate base amounts through November 2003 was about $6.5 million. Tr. at 1404. In addition, Staff estimated the customer benefit of updating Idaho Power's December 2003 projection to be an additional $1.3 million. Tr. at 1405. On March 31, 2004, under direct examination, Mr. Holm provided an update of the actual account balances at December 31, 2003. The resulting revenue requirement difference between budget and actual numbers is $7.6 million.[1]

The Commission finds it most reasonable to base its decision on actual account information for the entire test year. Although Idaho Power witness Smith testified that the actual account data would "validate" the projected amounts (Tr. at 537), we find the $7.6 million revenue requirement difference between the actual and forecasted half of the test year to be substantial. It would make little sense to carefully track account information through to the end of the test year only to disregard actual amounts in favor of forecasted numbers that are less accurate and merely estimates. The Commission accepts this adjustment as fair and reflective of the best information available to us in the record.

2. Annualizing Plant Adjustments.

When significant plant improvements are completed late in the test year, the challenge is to reasonably include the investments in the test year in a way that fairly compensates the Company for its investment, but also fairly treats ratepayers by matching investment revenues with investment expenses. Idaho Power proposed, and the Commission has historically approved, use of an "average" rate base rather than a "year-end" rate base on which

[1] The test year revenue requirement difference between budget and actual numbers is $7.6 million if the Company's 1.642 gross-up rate is used. If Staff's recommended tax gross-up rate of 1.446 is used instead, the revenue requirement difference between the 2003 test year budget and actual data is approximately $6.6 million. The $6.6 million is calculated by adding the $6.5 million difference between budget and actual data through November 2003 (Tr. at 1404) to the additional $1.3 million forecast for December 2003 (Tr. at 1405); and then subtracting the $1.2 million Company revenue requirement benefit as updated by Mr. Holm under direct examination on March 31, 2004 for the actual account balances at December 31, 2003 (Tr. at 1449).

to earn its authorized investment return. Idaho Power proposed to increase its overall rate base in the amount of $19,779,389 by annualizing plant improvements completed in the last part of the test year. The rate base impact can be attributed to $6,621,907 for the rewind of Bridger Unit No. 3 and $13,157,482 for completion of the Brownlee-Oxbow transmission line. Tr. at 555.

Staff witness Leckie objected to these Idaho Power adjustments as "not consistent with Commission-approved methodology for calculating an average-year rate base." Tr. at 1545. Mr. Leckie contended the adjustment for these plant additions "has the same effect as if Idaho Power were using the year-end balance for these additions to plant in determining rate base." *Id.* Micron also testified that the Company-proposed annualization adjustment created a clear mismatch of revenues and expenses. Rather than recommending disallowance of the Company's proposed adjustments, however, Micron witness Peseau advocated annualizing revenues to year-end levels assuming a 4.06% growth rate.[2] Micron's annualizing adjustment would add $9,731,765 to Idaho Power's test year revenues. Tr. at 2428-2430.

In rebuttal, the Company recognized that there has been considerable debate over use of an average rate base or a year-end rate base. Company witness Gale argued that the key question is "whether the investment in plant under consideration produces revenues." Tr. at 3154. "If the plant that is added does not add additional revenue or if that additional revenue is *de minimis*, then there is no mismatch of revenues and expenses when the full or year-end investment of the plant item is included in rate base." *Id.* Idaho Power stated that the Bridger rewind and the Brownlee-Oxbow transmission line were completed for system reliability purposes and will not generate additional revenues. Regarding the Brownlee-Oxbow transmission line, Mr. Gale argued "that line was constructed for reliability purposes to add an additional power source to the greater Boise area and does not add additional revenue to the test year that is not already included." Tr. at 3156.

We generally believe that including investment in the calculation of average-year rate base as if it were in service the entire year when it was not, as proposed by Idaho Power in this case, creates a mismatch between test year revenues and expenses. Although the Company insists that these plant investments will not generate additional revenues, the Commission has previously noted that "in terms of cash flow all depreciable investments are revenue producing."

[2] The Commission declined to adopt Micron's annualization of revenues because it would exacerbate the mismatch issue, as much of the additional revenue that Micron proposes to include is associated with distribution and other consumer-related plant that has not been annualized.

Order No. 20592 at 12-13. Both the Bridger rewind project and the Brownlee-Oxbow transmission line should decrease Idaho Power's future maintenance costs. Plant improvements that increase reliability, especially ones that also "add an additional power source to the greater Boise area," will undoubtedly enable the Company to earn additional revenues because new customers will be added to its more reliable plant. Tr. at 3156. We also believe that this new transmission line may facilitate additional wheeling or allow the Company to sell excess capacity to other parties on this line or on other lines where capacity has been freed up.

Generally speaking, the Commission expects all utilities to attempt to identify expense saving and revenue producing effects when proposing rate base adjustments for major plant additions. It is unfair to ratepayers to assume that the investment in these plants will not increase Company revenues or decrease Company expenses in the future. Further, it is unreasonable to expect the Commission to allow full recovery of plant investment as if the plant had been in operation the full year without a corresponding adjustment to revenues and expenses.

In this case, we want to make clear to Idaho Power and the financial community that the Commission supports prudent plant investment constructed to improve system reliability – particularly transmission facilities. We find it reasonable to allow Idaho Power's proposed annualizing plant adjustment for the Bridger rewind and the Brownlee-Oxbow transmission line based on the particular circumstances of this case. Accordingly, the test year rate base will be increased by $19,779,389 to account for plant additions that are currently in service and benefiting customers.

However, we find it difficult to justify annualizing plant rate base adjustments without the Company first attempting to calculate all revenues and expenses, including expense reductions that would have occurred had the plant been in operation the entire year. Rather than deny the adjustment outright or require Idaho Power to wait for its next rate case to include this plant in rate base, we find it is just and reasonable to impute increased revenues or reduced expenses of $995,497 as a proxy for items that were not properly reflected under the matching concept.

Although the proxy's specific calculation should not be used as precedent in other cases, this proxy amount generally incorporates recognition that on average, plant facilities recorded in the same account category will over time have similar characteristics related to the average operation of the system. Information associated with these categories provides the best information available at this time for use as a proxy to determine opportunities available for additional revenues or reduced expenses. The categories included in the Company's annualization adjustment are Steam Production, Transmission Station Equipment and Transmission Lines. New plant requires less maintenance than older plant so the use of averages is probably conservative when estimating the benefits of reduced maintenance costs and increased reliability. Increased reliability provides opportunities not previously available that directly or indirectly generates additional revenues or reduces expenses. This conservative estimate does not include arbitrage or ancillary service opportunities that may be enhanced over other transmission lines as reliability increases. It also does not recognize the potential for increased customer revenues when new growth is served with the increased reliability. Only the average ratios of revenues and expenses compared to the total plant in each category have been used to develop the proxy figure.

The approximately $2 million cash flow associated with this plant from depreciation and the return is greater than the $995,497 imputed for revenues and reduced expenses. Even with the imputation, the Commission has allowed Idaho Power to recover all out of pocket expenses associated with this plant and still have a positive cash flow. The impact of our adjustment is less than either the Staff-proposed $19,779,389 adjustment to rate base and $623,915 adjustment to expenses, or the $9,731,765 Micron-proposed adjustment that attempted to address this mismatch by reducing the Company's revenue requirement.

Considering this Commission's desire to adequately support reasonable infrastructure investments, we believe our overall result is fairer to Idaho Power than the adjustments recommended by the other parties. It is also a reasonable outcome for ratepayers, who will experience greater service reliability as a result of this plant investment. Any additional revenues or reduced expenses will be known and properly reflected in the next general rate case that Company witness Gale indicates can be expected in "two to three years." Tr. at 3193. The Company is directed to better identify all the increased revenues, reduced expenses or any other benefits if it wishes to annualize plant investment in future cases.

3. IERCO Investment – Unused Equipment Adjustment.

The primary purpose of the Idaho Energy Resources Company (IERCO) is to mine coal for the Bridger Power Plant. Idaho Power treats IERCO's coal operations as a part of Idaho Power's utility operation and adds current year IERCO earnings to electric operating income and its investment in IERCO to net electric rate base. Tr. at 521-22. Idaho Power reduced IERCO's rate base for notes payable of $5,909,558 and associated interest income of $78,613. Tr. at 522-23. Staff recommended further reducing the IERCO rate base by $280,937 for equipment no longer used and useful. Tr. at 1571. The assets identified as no longer used and useful are: a dragline and bulk lube system, the dragline monitoring, and inergin fire system for the dragline; two 62-yard buckets; a Hitachi power shovel; a lowboy tractor; and a 1995 Ford truck. Tr. at 1573.

The Commission accepts adjustments to IERCO rate base made by Idaho Power, and also finds Staff's recommendations to be reasonable and fair. Assets no longer used in utility operations should be removed from rate base. Accordingly, Idaho Power's one-third interest in the IERCO rate base, as reflected in Idaho Power's rate base, shall be reduced by $280,937. This rate base adjustment will also reduce annual depreciation expense for the equipment no longer used and useful by $133,554.

4. Biological Opinion Adjustment.

Idaho Power included in rate base its costs incurred defending against a lawsuit related to a National Marine Fisheries' Biological Opinion. In March 1997, the Sierra Club Legal Defense Fund filed a "notice of intent to sue" for violation of the Endangered Species Act with the Federal Energy Regulatory Commission on behalf of several environmental groups alleging that operation of the Hells Canyon Complex imperiled certain anadromous fish. Tr. at 634-36. Idaho Power defended its Hells Canyon operations, incurring attorney fees totaling $654,740 during 2000 and 2001. Idaho Power capitalized the entire amount and included it in rate base. Tr. at 1567. Staff objected to this rate base adjustment, contending the costs incurred should have been booked as an expense rather than to rate base. Staff witness Leckie argued, "without some benefit that would extend into the test year and beyond, it is not reasonable for Idaho Power to capitalize these expenses and include them in rate base." *Id.*

In rebuttal testimony, Idaho Power explained the reason for capitalizing these defense costs. If the challenge brought to its Hells Canyon operations had been successful, it would have impacted each year of operation into the future. Tr. at 636. Thus, Company witness Prescott contended the Company's defense "prevented negative impacts to revenues and expenses in the test year as well as years into the future." Tr. at 637.

The Commission finds that the legal expenses incurred by the Company to oppose the legal action regarding the Biological Opinion should be booked in the year incurred as an expense, rather than capitalized and added to rate base. We find this to be reasonable and consistent with Idaho Power's expensing of Snake River Basin Adjudication legal costs to defend the Company's water rights over the last decade. These Biological Opinion legal expenses were incurred over a short duration and are not the type of expense to be normally capitalized. Accordingly, the rate base requested by Idaho Power shall be decreased by $654,740.

5. Brownlee Woodhead Park Adjustment.

Idaho Power included in rate base investments it made for improvements to the Brownlee-Woodhead Park that is part of its Hells Canyon Complex. The costs of the improvements totaled $7,525,237. Staff argued this amount should not be allowed in rate base until after Idaho Power completes relicensing of its Hells Canyon hydroelectric plants. Staff witness Leckie argued "it is reasonable to conclude that Idaho Power is hopeful that these additional improvements will facilitate a smoother relicensing process," and that "the extent of the park reconstruction and enhancements were meant to exceed the life of the current license term." Tr. at 1564-65.

In rebuttal testimony, Idaho Power pointed out that the park improvements were completed in 1996 and are currently used extensively by the public. Tr. at 630. Company witness Prescott testified that while "the primary motivation for the improvements was compliance with the existing FERC license," the Company conceded "that a significant benefit of rebuilding the facility prior to relicensing was to demonstrate responsiveness to public needs and moderate requests for additional facilities at Woodhead Park during the relicensing process." Tr. at 631. There is no question that the Woodhead Park improvements are complete, used and useful. Tr. at 633.

The Commission finds that the $7,525,237 in improvements made by Idaho Power to Woodhead Park should be capitalized and included in rate base. The evidence is uncontroverted that the improvements were completed as a requirement of the existing and/or future FERC licenses for Idaho Power's Hells Canyon Complex, and that the improvements are currently used and useful. Although there is some question regarding whether the Company built the park larger than the current license requires, the Commission believes doing so was not imprudent and may have been cost-effective in light of the current relicensing proceedings. The Commission also notes that the inclusion of these costs in rate base serves as a reminder of the financial impact that projects related to relicensing have on customer rates. We encourage Idaho Power to evaluate current park usage fees to minimize park costs to be recovered from ratepayers in the future. Tr. at 1566.

6. Known and Measurable Physical Plant Improvements.

Idaho Power proposed an upward adjustment to rate base for plant improvements it expects to complete by May 2004. Because the costs are known and measurable, Idaho Power added $18,388,690 to the 2003 test year rate base for upgrades to the Brownlee-Oxbow transmission line and Star, Vallivue, Midrose and Goshen transmission stations. Tr. at 555. Staff witness Leckie agreed these known improvement costs should be included in rate base, but objected to the manner in which the Company added the costs, noting "it is a question of how the cost of these projects should be included in computing the 13-month average rate base." Tr. at 1555. The Company proposed to add the entire amount to each month of the test year rate base, and also increase related test year expenses for these projects by $447,375 for depreciation, $112,171 for property taxes, and $8,199 for insurance. Noting that the Company did not make any attempt "in its testimony or exhibits to quantify customer benefits that result from these additions to plant," Mr. Leckie claimed including only the costs without adjusting revenues created a mismatch in the test year that "is not fair to ratepayers." Tr. at 1556. Staff recommended the project costs be added to rate base only in one month of the test year and then averaged over the 13-month test year. In that way, the projects would be recognized in rate base with no need for an offsetting increase in revenues. Staff's recommendation would decrease the Company's adjustment to rate base by $16,974,175. Tr. at 1561.

Micron also objected to the Company's proposed known and measurable adjustments for major plant additions. Dr. Peseau testified that with the exception of depreciation, all remaining known and measurable adjustments should be denied because they are not sufficiently certain to occur and Idaho Power has made no effort to quantify offsetting revenue benefits like the embedded cost of long-term debt. Tr. at 2434-36. Micron's proposed adjustment would reduce Idaho revenue requirement by $11,768,222. Tr. at 2438.

In rebuttal testimony, the Company argued that the project costs should be included in the test year rate base. Although falling outside the test year, Company witness Obenchain insisted they "will be plant-in-service and used and useful by the time the rates determined by this proceeding go into effect." Tr. at 2792. He also maintained that "customers are receiving the benefits of these sizable plant investments now," these transmission projects increase the system reliability, and that "even though these investments may not produce revenues[,] they do produce benefits for customers." Tr. at 2795.

It is true that these projects, if completed on schedule as planned, will be operational by the time new rates go into effect, and thus produce a benefit for customers. But it also is true that these projects produce a benefit for Idaho Power that may include additional revenues, and the Company made no effort to quantify the benefits it will receive from the additional investments. The Commission generally believes that putting the known and measurable adjustments in rate base for a full year creates a mismatch between revenues and expenses in the test year if benefits are not needed too. Although the Company insists that these plant investments will not generate additional revenues, the Commission has previously noted above and in Order No. 20592 that all depreciable investments produce revenue. Idaho Power's newly built transmission stations will reduce maintenance expenses for the old Goshen station and create additional revenues from the growth served by the new Star, Vallivue and Midrose substations. Again, we know these benefits exist but are without the information necessary to precisely calculate them, and thus we must use some reasonable means of estimating them.

As we explained in the "Annualized Plant Adjustments" section (*supra* at 5), we generally expect all utilities to identify expense saving and revenue producing effects when proposing rate base adjustments outside the test year for major plant additions. In keeping with our desire to promote reasonable plant additions, we also find it reasonable to allow Idaho Power to include the $18,388,690 of known and measurable plant adjustments for the Brownlee-Oxbow transmission line and Star, Vallivue, Midrose and Goshen transmission stations in rate base and earn a return on this investment.

However, we also believe it is critical to match revenues and expenses to these plant additions. We, therefore, find it reasonable to use a proxy for the actual additional revenues or reduced expenses that have not been adequately quantified by Idaho Power and impute $1,031,733 of revenue and reduced expenses in calculating the Company's revenue requirement. This revenue and expense reduction imputation for the known and measurable adjustment is calculated in the same manner as that imputed for the annualized plant. The account categories for the known and measurable plant include Transmission Station Equipment and Transmission Lines.

The impact of this imputation is less than either the $16,974,175 Staff-proposed rate base adjustment or the Micron-proposed adjustment that attempted to address this mismatch by reducing the Company's revenue requirement. Again, this imputed revenue may be conservative but we believe the overall result is just and reasonable.

The approximately $1.9 million in cash flow associated with this plant from depreciation and the return is greater than the $1,031,733 imputed for revenues and reduced expenses. Even with this imputation, the Commission has allowed Idaho Power to recover all out of pocket expenses associated with this known and measurable plant adjustment as it did with the annualizing adjustment. Although this imputation achieves a fair result in this case, the specific calculation should not be used as precedent in other cases.

7. Document Management System.

Idaho Power added $106,275 to the test year rate base for the entire cost of a Shareowners' Document Management System. Noting that Idaho Power only has one shareowner, IDACORP, Staff testified that only IDACORP has enough shareowners to require a shareowners' document management system, and thus the benefits of the system flow mostly to IDACORP. Tr. at 1569. Staff witness Leckie recommended the cost of the system be shared equally between the ratepayers and shareowners, which "is the same treatment as that used to allocate Board of Directors' fees." Tr. at 1570. Staff's recommendation would remove $53,137 from Idaho Power's proposed rate base, and reduce the Company's annual depreciation expense by $7,295. *Id.* The Company offered no response to Staff's proposed adjustment in its rebuttal testimony.

The Commission finds that including the entire cost of the Shareowners' Document Management System in rate base would be unfair to ratepayers. Because the system benefits IDACORP in its administrative responsibilities much like the fees paid to its Board of Directors, we find that it should be allocated the same as the Board of Director's fees in this case. Therefore, only one-half the cost of the system should be included in Idaho Power's rate base. Accordingly, Idaho Power's rate base adjustment will be reduced by $53,137 reflecting the cost of the system, and by $7,295 for reduced depreciation expense.

8. Prepaid Pension Expense.

Idaho Power included in test year rate base $17,800,477 for prepaid pension expense. Staff witness English contended none of the prepaid pension amount should be included in rate base. He argued that "prepaid pension expense is not an asset of the Company, but rather an asset of the trust that maintains the assets of the pension plan," and, as such, it "is not an asset that provides electric service on which shareholders are entitled to earn a return." Tr. at 1510-11. Staff insisted the prepaid pension amount "is clearly not an asset that should earn a return if Idaho Power has no ownership of the funds, no discretion on how those funds can be used, and those funds cannot be returned to them." Tr. at 1511. Mr. English also pointed out that the Company "has not made any contributions to the pension plan since 1995, and any contributions prior to that were funded by customers." Tr. at 1512.

Idaho Power witness Fowler argued in rebuttal testimony that the prepaid pension amount should be included in rate base because the "asset represents a use of cash. It is a consequence of providing a pension plan for employees, following the required rules for funding the plan, and recording the expense of the plan on the Company's books." Tr. at 2870-71. Idaho Power asserted the pension plan itself "is an important benefit for attracting and retaining the employees needed to provide reliable electric service to the Company's customers." *Id.*

The Commission agrees that the Company's pension plan is important to its employees and helps retain effective workers. The question, however, is whether an accumulated pension amount should be included in rate base for ratemaking purposes so that customers pay a return on the prepaid pension amount.

Idaho Power collected enough money in rates from customers since the last rate case to fund its pension plan. Because Idaho Power did not accurately predict that its pension fund would experience favorable investment results, the pension fund was subsequently over funded. The over funded portion exceeded the amount the Company recorded on its books, creating a prepaid pension asset. If Idaho Power had predicted this at the time of its last rate case, the Company's revenue requirement would have been reduced, ratepayers would not have paid in as much, and Idaho Power's pension plan would not be as over funded as it is now. An over-funded pension plan benefits the Company and its employees.

Because prepaid pension assets result from accounting procedures rather than funds actually contributed, they are not the type of asset providing electric service upon which Idaho

Power and its shareholders are entitled to earn a return on investment. Furthermore, as a result of these prepaid pension assets, Idaho Power's actual cash contribution during the 2003 test year was zero. Evidence in the record indicates that no contributions will be made in the next several years as well. Tr. at 1509, 2879. Therefore, we find it is unreasonable to include the $17,800,477 prepaid pension amount in rate base.

9. Capitalized Incentive Pay Adjustment.

Idaho Power proposed an approximately $5.1 million increase in payroll expense for incentive pay, but later updated its forecast of incentive payments to $4,837,358 instead of the original $5,114,821. Tr. at 1426. The incentive plan, implemented by the Company in 1995, pays employees an additional percentage of their base salary when IDACORP's earnings per share reach certain levels. Staff argued that employee incentive plan costs should not be included in the test year rate base for two reasons. First, employees already receive adequate compensation. Second, the incentive amount is tied to IDACORP earnings, not Idaho Power's performance. Because a portion of employee incentive payments are capitalized, Staff identified the amount of $7,741,747 that should be removed from rate base if the Commission disallows the incentive plan costs in the test year. Tr. at 1427. Micron also recommended denial of the incentive pay adjustment because it is not certain to occur, its net impact on revenue requirement cannot be quantified, and the adjustment could as easily be positive or negative. Tr. at 2432-33.

Idaho Power argued on rebuttal that Staff's arguments that incentive pay overpays employees in the current labor market and does not benefit customers are erroneous. Company witness Minor stated that if Idaho Power had not implemented an incentive pay plan and had continued to maintain the salary structure at the 60th percentile base level, base compensation would be $7-8 million higher. Tr. at 2827. If the Commission denies its requested incentive pay expense, Mr. Minor testified that management will be forced to make adjustments in base pay to bring its total class compensation back to the 60th percentile with a resulting increase in Idaho Power's fixed total compensation. Tr. at 2829-31, 2840, 2846.

As discussed in greater detail in a following section dealing with adjustments to test year revenues and expenses, the Commission concludes the incentive plan costs should not be included in the test year. We only note here that one effect of that decision is a reduction to the test year rate base of $7,741,747 to remove the capitalized portion of the plan costs from rate base along with the associated $230,594 depreciation expense.

10. Depreciation Expense and Accumulated Depreciation Adjustment.

In 2003, Idaho Power filed and the Commission approved changes in the depreciation rates for the Company's plant investments. In this case, proposed test year adjustments to the accumulated depreciation balances are based on the depreciation rates it initially sought in Case No. IPC-E-03-7. Staff pointed out that the Company stipulated to the new depreciation rates in that docket and recommended the test year depreciation accounts reflect the new depreciation rates approved by the Commission in Order No. 29363. More specifically, Staff recommended the accumulated depreciation balance included in rate base be reduced by $2,205,647, and the annual depreciation expense be reduced by $4,411,294 to reflect the Commission findings in that Order. In rebuttal testimony, the Company stated that, "obviously, the Company agrees with the reduction of depreciation expense of $4,411,292. This amount is reflective of the settlement depreciation case, IPC-E-03-7" that was approved after the filing of the general rate case. Tr. at 3180.

Multiple parties (including Idaho Power) stipulated to these rates that were approved last October. Given Idaho Power's agreement with the reduction in the depreciation expense, it follows that the accumulated depreciation in rate base must also be reduced by $2,205,647. Consequently, the Commission finds it appropriate that the accumulated depreciation amount Idaho Power proposed for rate base be reduced by $2,205,647.

11. Cloud Seeding.

Idaho Power included in the test year operating expenses of $897,448 and capital costs of $214,600 for a cloud seeding program. Cloud seeding is an experimental program to artificially increase winter precipitation. Staff witness Hessing testified that the Company "did not provide enough information in its filing for Staff to make a recommendation on the merits of cloud seeding." Tr. at 1628. Noting the "experimental and somewhat controversial nature of cloud seeding programs and the sizable amount of money requested to be included in rates," Mr. Hessing recommended the costs be removed from the test year if the Company did not provide additional information demonstrating that the costs were prudently incurred. Tr. at 1629. The Irrigators also objected to the cloud seeding costs. They reviewed Idaho Power's response to questions about Account 536, the expense account that includes the cloud seeding program, where the Company stated "the cloud seeding program was started in late 2002, but the test year (2003) includes expenses for a full year of operation." Tr. at 2541. Mr. Yankel testified that "cloud seeding is not a regular activity and should not be included as a normal test year expense." *Id.*

In rebuttal testimony, Idaho Power responded to Staff's complaint that the Company had not provided information about the cloud seeding program. Idaho Power acknowledged, "There is no question that cloud seeding is somewhat controversial and experimentation is ongoing." Tr. at 640. The Company provided a brief history of its past interest in a cloud seeding program, culminating with the hiring of a full-time meteorologist in 2002 and the initiation of an operational program in late January 2003. Tr. at 642. Cloud seeding began in February and continued until April 15, 2003. *Id.* Idaho Power explained that the Company will do "an in-depth evaluation phase over the current and the next winter seasons," and that a university affiliated institute "has initiated work this winter to evaluate the program." Tr. at 644-46. Negative results for the aircraft or ground seeding component "that cannot be adequately explained will likely lead to cancellation of that piece of the program." *Id.* The Company was optimistic that "results from the assessment are expected to demonstrate the effectiveness of the project." Tr. at 652.

Given the experimental nature of the cloud seeding program and the lack of demonstrated effectiveness, the Commission finds that cloud seeding expenses are not a normal test year expense and should not be included in the test year. The program lasted only three and a half months of the test year and results are at this time speculative. Evaluation and analysis of the program could lead to its cancellation, and that evaluation is only beginning. Under these circumstances, it would be unfair to ratepayers to include all cloud seeding program costs in the test year as if it were continuing each year into the future. Moreover, we believe that the money invested in cloud seeding could be better spent on programs that will provide a known benefit, such as demand-side management or smart meters.

12. Danskin Power Plant.

Idaho Power included in rate base the cost of constructing the Danskin Power Plant, which totaled $53,440,376. This figure does not include amounts paid for natural gas costs, which are flowed through the Power Cost Adjustment (PCA) and thus reconciled with expenses in this case. Danskin was completed in the summer of 2001 to serve as a peaking facility, that is, it is "primarily used to meet extreme load conditions, which for Idaho Power Company usually occur during the later afternoon or evening hours in mid summer." Tr. at 603. Staff witness

Sterling's testimony reviewed the conditions at the time Danskin was developed and recommended the Commission include the construction costs in rate base. Tr. at 1649.

The Industrial Customers of Idaho Power (ICIP) witness, Dr. Reading, recommended "the Commission not give the Company rate base treatment for Danskin." Tr. at 1334. ICIP noted that the Commission, when considering approval of the construction of Danskin, asked the Company to provide more information about alternatives it considered and the forecasted need for the facility. ICIP maintained that the Company failed to provide any additional information in this case, and that Danskin is operating significantly fewer hours per year and at higher costs than anticipated. Tr. at 1314-25. Moreover, ICIP argued that Idaho Power should have reassessed Danskin's economic viability at the time the Commission approved its Certificate. Tr. at 1334.

Idaho Power in its rebuttal testimony responded to the criticisms of ICIP and provided additional information regarding the Danskin plant. Tr. at 603-27. Mr. Prescott pointed out that Danskin is a "resource of last resort," which means the plant is operated only "when there is no transmission available or when market prices are so high that market purchases are unattractive." Tr. at 613.

The Commission finds that Idaho Power is entitled to include Danskin plant costs in rate base. The extraordinary conditions that existed at the time Danskin was developed warranted a rapid response by the Company, and justify the investment in a peaking facility that by design is more costly to operate than other types of facilities. While the hourly operation numbers projected by Idaho Power have not materialized and are unlikely to do so in the foreseeable future, they are within the hours of operation discussed for purposes of its certificate of convenience and necessity. For these reasons, we believe that authorizing the requested Danskin rate base amount and associated expenses to be appropriate and reasonable.

Although the Company did not provide additional information requested by the Commission until after its omission was pointed out by ICIP, we decline to withhold ratemaking treatment of its investment solely on that ground. The Company's inattentiveness to this filing requirement made it considerably more difficult for us to review Danskin's plant costs for rate base recovery. We expect the Company will not place the Commission in a similar position when it seeks cost recovery of the Bennett Mountain generating facility. Tr. at 3193.

ADJUSTMENTS TO TEST YEAR REVENUE AND EXPENSES

Micron had a general criticism to Idaho Power's adjustments to test year expenses. Dr. Peseau noted that the Company proposes to use test year revenues, after updating the projected figures with actual 2003 figures normalized for weather and other standard adjustments, but that "expenses and rate base are treated in a much different manner." Tr. at 2426-28. Furthermore, by annualizing operating and maintenance expenses and certain rate base items, Idaho Power creates a mismatch between revenues and expenses that is made worse with its proposed known and measurable adjustments. The result is a "partially projected test year ending on May 31, 2004 for rate base and expenses, matched against revenues centered on June 30, 2003." Tr. at 2428. To correct the mismatch, Micron recommended that revenues be annualized to 2003 year-end levels, which would add $9,731,765 to Idaho Power's test year revenues. Tr. at 2428-29.

The Commission recognizes that Micron is correct and that a mismatch of revenues and expenses exists. We have chosen, however, to address this with individual adjustments rather than annualizing revenues to 2003 year-end levels because annualizing revenues for customer growth would create a different mismatch between rate base, revenues and expenses. Not all customer-related plant and expenses were annualized or proformed to year-end levels, so we decline to adjust revenues in total to year-end levels in this case.

Before discussing individual adjustments to test year revenue and expense accounts, we note that Idaho Power accepted some of the adjustments proposed by the other parties, resulting in a reduction of the additional revenue requirement requested by the Company. Idaho Power originally requested approval to increase its annual revenue by $85,561,910, but reduced the amount to $70,675,029 after accepting some of the test year adjustments recommended by Staff and other parties. Tr. at 3183. The adjustments Idaho Power accepted included changes to pension expense, memberships and contributions, year-end payroll, the Standard Salary Adjustment (SSA), incentive pay, and depreciation. Exhibit 80.

1. Total Operating Pension Expense Adjustments.

Idaho Power included in its test year expenses $9,188,163 for employee pension expenses, including a proposed expense adjustment of $2,170,163 to change the pension expense accounting from Net Periodic Pension Cost to Service Cost. Tr. at 529, 1253, 1497-98. Company witnesses justified the additional expense based on the Service Cost standard as more accurately reflecting future pension costs and necessary to remove market volatility and interest rate volatility. *Id.* and 1252-53. Staff disagreed with the expense adjustment to reflect Service Cost, and in its rebuttal filing the Company agreed the $2,170,163 pension cost adjustment should be removed from the test year expenses. Tr. at 2858, 3181.

Staff also recommended two other reductions in test year pension expense, one totaling $1,379,149 and the other totaling $5,638,851, that together would bring test year pension expenses to zero. Staff's first recommendation was to disallow additional pension expense resulting from Idaho Power's test year changes to actuarial assumptions used in calculating pension costs. Staff testified that the Company's reduction in the pension plan discount rate and future expected return on plan assets were not justified by any change in circumstances, and "the fact that these changes served to increase pension expense during the test year seemed a little suspect." Tr. at 1501-02. Staff recommended that the long-term rate of return on pension assets of 9.0% used by Idaho Power prior to the test year continue to be used, resulting in an expense reduction of $1,379,148 in the test year. Tr. at 1504. In rebuttal testimony, the Company's pension expert testified that many corporations lowered expected long-term rates of return for their pension plans between 2002 and 2003. Tr. at 2859. For example, the median assumed long-term rate of return on pension assets for the 100 largest corporations declined from 9.50% to 9.00%. *Id.* Thus, Idaho Power believes it is reasonable to reduce its assumed pension return from 9.00% to 8.50%.

Staff's final adjustment to test year pension expense was to reduce the expense by $5,638,851, bringing the test year pension expense to zero. Staff witness English explained that this adjustment "is a reconciliation between cash and accrual accounting." Tr. at 1505. In other words, although the Company accrues a pension contribution on its books for financial reporting purposes, Idaho Power "did not contribute to the plan for 2003 and therefore did not incur any actual costs." *Id.* In fact, Mr. English testified the Company "could not have legally contributed to the pension plan [in 2003] without incurring penalties." Tr. at 1507-08. Furthermore, the Company has not been able to contribute to the pension plan since 1995, but "continued to recover in rates more than $3 million per year from ratepayers for pension expenses." Tr. at 1508. Mr. English concluded the Company "has recovered nearly $19 million more than [it] actually contributed to the pension plan since 1993." *Id.* Idaho Power opposed Staff's final adjustment to the test year pension expense. Company witness Fowler testified "the critical need for using a consistent methodology from year to year is disregarded when the pension cost allowed is switched from a FAS 87 basis [accrual accounting methodology] in one rate filing to a cash basis in the next." Tr. at 2864.

Based on the information in the record and the Company's concurrence with Staff's recommendation, the Commission accordingly accepts the reduction in test year pension expense of $2,170,160 reflecting the use of Net Periodic Pension Cost rather than Service Cost. The Commission also finds it reasonable to leave the long-term assumed rate of return on pension assets at 9.00% based upon the testimony presented and returns on pension assets that have averaged 12.97% over the past 15 years. Tr. at 1504, 2871. Accordingly, the Commission will reduce Idaho Power's adjustment to the test year pension expense by $1,379,148.

On the evidence presented in this case, the Commission also finds the final adjustment proposed by the Staff for the pension plan expenses to reconcile cash and accrual accounting to be fair and reasonable. Accordingly, the test year pension plan expenses will be reduced to zero, reflecting the actual pension plan expenses incurred by the Company. Idaho Power has said that one can "expect a general rate case in two to three years." Tr. at 3193. The pension expense can be re-evaluated at that time to determine if a ratemaking adjustment is warranted.

2. Memberships and Contributions Adjustment.

Staff proposed to reduce test year operating and maintenance expenses by $326,014 to disallow some of the membership and association dues paid by the Company. Tr. at 1513-14, Revised Exhibit 110. The bulk of the $246,048 reduction recommended by Staff removes 75% of the dues paid to the Edison Electric Institute (EEI). Tr. at 1514, Exhibit 110. Staff's remaining reductions are for dues paid to Rotary Clubs, Lion's Clubs, Chambers of Commerce, political parties, the Arid Club in Boise, and small fees paid to a number of other organizations. Staff recognized the Company's participation in various organizations may enhance the Idaho Power image and provide a social presence for the Company and its employees. Tr. at 1514.

The Company in rebuttal testimony agreed that some of the fees identified by Staff should not be included in test year expenses. Specifically, the Company agreed that the amount it included should be reduced by $38,066, representing fees paid to political parties and charitable contributions made by the Company. Tr. at 3143-46. Idaho Power vigorously opposed elimination of the remaining expenses as having legitimate business purposes, particularly its EEI-related expenses. Tr. at 3131-47.

The Commission has consistently disallowed for ratemaking purposes political and charitable contributions and a portion of the dues and association fees paid by the Company. We find it reasonable and appropriate to do so in this case. The Commission agrees with Staff and the Company that $38,066 should be removed for political and charitable contributions. We also recognize that the Company's participation in some organizations has a legitimate business purpose and benefits its customers. The Commission further finds that EEI offers its members education on industry issues and management training, both of which are legitimate business-related expenses. Accordingly, we adopt only one-third of Staff's proposed expense reduction to reflect remaining activities that are not appropriately in rates. Therefore, the Commission determines it just and reasonable to reduce the test year contribution and membership expenses by $95,983.

3. Interest on American Falls Bonds and Pollution Control Bonds.

Idaho Power made a test year adjustment to its interest expense on American Falls bonds, claiming an increase in 2004 was known and measurable in the amount of $297,436. The American Falls bonds are guarantees reflected in operating expenses as a falling water payment, not in the cost of debt and overall rate of return like other bonds. Staff witness English recommended disallowing the Company's adjustment, arguing the increase in interest expense above the test year amount was "neither known nor measurable." Tr. at 1523. Idaho Power originally forecast the interest expense for the second half of 2003, as well as for 2004. Staff noted that the Company's forecast methodology assumed a jump in the bond interest rate from 2.3% on December 31, 2003, to 4.2% the next day, January 1, 2004. Tr. at 1522. Because Staff believed "the methodology used by Idaho Power grossly overstates the forecasted interest rate," Mr. English recommended the test year adjustment proposed by Idaho Power to increase American Falls bond interest expense in the amount of $297,436 be disallowed. Tr. at 1523. In addition, Staff proposed a reduction in the test year interest expense based on the most recent interest rate available, 2.35% on January 20, 2004. *Id.* If this rate were applied to the test year American Falls bonds, the test year interest expense would be reduced by $29,418.50. *Id.*

Staff also recommended a similar adjustment to cost of debt and test year interest expense related to the Pollution Control Revenue Bonds. As with the American Falls bonds, Idaho Power used an estimated interest rate based on a ten-year average of the Bond Market Association (BMA) index to state the interest expense for these Pollution Control Bonds. Tr. at 1524, 2754-56. Staff witness English testified "the ten-year average is not reflective of the current rate or the rates for the last several years." Tr. at 1524. Instead, Staff recommended "using the current interest rate as of December 31, 2003 to determine the actual 2003 year-end cost of debt." Tr. at 1525. If the year-end interest rate is used, the test year interest expense on the Pollution Control Bonds would be reduced in the amount of $3,083,000. *Id.*

In rebuttal testimony, Idaho Power witness Gribble noted that the American Falls bonds interest expense "is based on a variable interest rate with the interest rate resetting on a weekly basis." Tr. at 2756. If the bond interest expense is based on the latest variable rate of 2.35% on January 20, 2004, it would place "the Company at risk of not recovering its actual American Falls interest expense in a rising interest rate environment." Tr. at 2756-57. Although Idaho Power continued to advocate for a ten-year average rate, Mr. Gribble stated "the Company could support a five-year average methodology for determining the American Falls interest rate known and measurable expense adjustment." Tr. at 2757. Idaho Power noted that in its last rate case, the Commission accepted a five-year historical average for the Company's auction of preferred stock instead of using the actual rate as of the end of the test year. Tr. at 2753.

Based upon the record, the Commission finds it fair and reasonable to use a five- year historical average as the appropriate measure of variable interest expense for the test year. This BMA average rate of 2.48% reflects that the interest rate varies while providing an averaging to reflect the lower rates currently and in the past few years. This methodology provides a $225,308 adjustment to test year interest in the falling water expense for the American Falls Bonds. Using the five-year average as the base variable pollution control rate results in the Pollution Control Bonds at 4.24%, with an authorized debt return at 5.769% for use in the overall rate of return. The Commission's acceptance of this methodology in this case, however, does not constitute a guaranteed acceptance of this variable rate bond methodology in future rate cases as requested by Idaho Power in its rebuttal testimony. Tr. at 2756.

4. Operating Payroll Adjustments.

Idaho Power proposed two adjustments to test year payroll expenses based on projections the Company made for those expenses during the second half of the test year. Staff testified the Company's payroll adjustments are appropriate, but should be based on actual expenses for the test year rather than on projections. Staff initially testified that if actual costs are used, the two test year payroll expenses are reduced by $2,052,654 and $116,675.

The first payroll adjustment Idaho Power proposed was for an increase in its base salary expense, and resulted from the Company's projection that its annual salary expense would increase by $2,913,244 during the test year. Staff reviewed the actual December 2003 payroll amount and discovered the actual adjustment should be $2,052,654 lower than the Company projected. Tr. at 1429. Staff recommended the actual figure be used, which would increase test year salary expenses by $860,590 rather than the $2.9 million amount projected by Idaho Power. *Id.*

The second payroll adjustment recommended by Staff follows from the first. Idaho Power estimated the annual increase in its base payroll expense, referred to as a Salary Structure Adjustment (SSA), based on a historical average annual increase of three percent. Because the actual test year payroll was significantly lower than projected by the Company, the amount of SSA adjustment will be lower. Staff initially recommended a reduction in the test year projected payroll related to SSA of $116,675. Tr. at 1429. In supplemental testimony, however, Staff witness Holm testified that neither the SSA amounts nor the incentive pay amounts (discussed in the next section) will be paid by the Company for 2003. Tr. at 1456. Staff argued that adjustments to the test year, for what the Company had said were known and measurable changes, should not be allowed. Staff contends, because the Company will not pay the SSA until 2005, if at all, the amount Idaho Power proposed to be included in the test year for SSA is not known or measurable. Staff recommended removing the entire adjustment to the test year for SSA pay in the amount of $2,241,595. Tr. at 1456.

In rebuttal testimony, the Company agreed with the reductions in test year payroll expenses of $2,052,264 and $116,675, based on actual payroll figures for the test year. Tr. at 3180-81. Company witness Minor also acknowledged that the SSA salary increase was not actually paid for 2003, and testified that current financial conditions "effectively deferred any upward Salary Structure Adjustment until such time that the Company's financial situation improves." Tr. at 2828.

As agreed by Staff and the Company, we find it reasonable to use the actual test year payroll expense numbers to calculate the revenue requirement and thus reduce payroll expense by $2,052,264. The Salary Structure Adjustment is based on year-end payroll and other unknown items such as earnings. It is not possible, therefore, to accurately calculate an SSA adjustment before January 2005. The Company acknowledged that current financial conditions do, and we believe they ought to, dictate a tightening of the Company's belt so to speak with regard to salaries. Because of this and the fact that the SSA adjustment is neither known nor measurable at this time, the Commission accordingly will remove $2,241,595 from test year expenses for the SSA.

5. Incentive Pay Operating Expense Adjustment.

Idaho Power made an adjustment to test year payroll expenses to add a component for its incentive compensation program. The Company originally projected a test year expense of $5,114,821, but reduced the amount of incentive pay to $4,837,358 based on actual year-end payroll figures. Tr. at 1414. Staff recommended that none of the incentive pay costs be included in the test year. Tr. at 1414-29. Staff witness Holm initially objected to this test year adjustment because "Idaho Power compensates its employees adequately without the incentive pay," and because the incentive pay plan is tied to IDACORP's earning goals, rather than to Idaho Power's performance. Tr. at 1427. He argued that "ratepayers do not directly benefit when IDACORP's earning goals are achieved or exceeded and thus should not fund this program." *Id.* In supplemental direct testimony, Mr. Holm identified an additional reason for disallowing a test year expense adjustment for the incentive pay plan. Idaho Power provided to Staff a copy of a Company newsletter that revealed no incentive pay would be paid for 2003, and thus the earliest that incentive pay would be paid by the Company would be January 2005, if at all. Tr. at 1456. Staff thus contended it was not possible or appropriate to make a "known and measurable" adjustment to the test year for incentive pay. *Id.*

Micron also testified that the incentive pay adjustment to the test year expenses should not be allowed. Micron witness Peseau testified that the proposed incentive pay "is not truly a known change because the incentive will presumably not be paid if the savings don't actually materialize. Furthermore, this type of incentive pay makes no sense unless it results in savings that exceed the incentive pay, in which case there is no need to further reward the Company for a program that will be essentially self funding." Tr. a 2432.

In rebuttal testimony, Idaho Power witness Minor explained the goal of the incentive pay program is "to focus utility employees' behavior on achieving operational excellence making a difference where they can through excellence in customer service, working efficiently, safely, and controlling utility operations and maintenance expenses." Tr. at 2827. Mr. Minor also acknowledged that, "in 2003, no incentive payout was made to Company employees." Tr. at 2819.

The Commission finds that the Company-proposed adjustment for the incentive pay program should not be included in the 2003 test year. First, Idaho Power adequately compensates its employees with the base salaries and additional benefits it provides, such as health benefits, pension plan contributions, and paid vacation time and holidays. In addition, because the incentive pay fluctuates, may not be paid at all in the future and was not paid in the test year, it would not be appropriate to include it as a known and measurable adjustment to the test year. Tr. at 2837-38. Finally, there is validity in Micron's argument that incentive pay should be self-funding. When earnings goals are achieved, it is not necessary to offer a financial reward for doing one's job with funds collected in rates when employees can share the gains with shareholders. Accordingly, the Commission rejects the Company's adjustment to the test year for incentive pay in the amount of $4,837,358.

The Commission is also concerned about the public perception of IDACORP benefits and employee bonuses when rates are increasing. We received considerable comment and testimony from customers expressing their frustration that Idaho Power's employees received bonuses and incentive pay during periods when customers had to "tighten their belts" to pay unprecedented high electric rates. It is difficult to explain why Idaho Power expected its ratepayers to pay extraordinary power supply costs while it simultaneously rewarded employees with bonuses. Although the Company maintained it was the performance of IDACORP that resulted in those bonuses, this disparity is evidence that Idaho Power's incentive plan is not properly aligned with the interests of its customers. With no incentive pay allowed in this case, customer rates do not include this controversial compensation.

6. Amortization of Unusual Cases.

Idaho Power included in test year expenses fees it paid to consultants in three different cases that occurred during the test year, including this general rate case. The fees paid for experts to participate in the three cases totaled $99,720. Tr. at 1443. Staff witness Holm argued that the cases are unusual "in that they are infrequent and will not occur during a typical year." Tr. at 1444. Mr. Holm further contended the costs should not be reflected in a single year in their entirety as an annual cost, and proposed "to amortize the expenses associated with these cases over five years instead of expensing them all at once." *Id.* If the consultant fees are amortized over five years, test year expenses as proposed by Idaho Power would be reduced by $79,776. *Id.* In rebuttal testimony, Idaho Power witness Gale stated that the Company retains outside expert services every year, and that "these three instances are indicative of the usual level of expense, not a one-time phenomenon and should be recovered fully in the test year." Tr. at 3160.

The Commission finds these outside consultant fees to be legitimate business expenses but atypical ones that do not carry on from one year to the next. Therefore, we find that these expenses should be recovered over a five-year period rather than in each year going forward. Test year expenses shall be reduced in the amount of $79,776. Fees that are typical remain in the test year expenses at the full amount.

7. Adjustments to Legal Expenses.

Staff recommended litigation expenses arising from the Company's participation in two cases referred to in testimony as the "California Refund Case" and the "Pacific Northwest Refund Case" not be allowed in test year expenses. The Refund Cases were brought by wholesale energy purchasers claiming that energy traders improperly manipulated spot market prices during the 2000-2001 energy debacle. Staff argued that it was IDACORP Energy's participation as an energy trader that created the litigation expenses incurred by Idaho Power, and thus those expenses should be born entirely by IDACORP or IDACORP Energy. Tr. at 1520-21.

In rebuttal testimony, Idaho Power witness Gale testified the Refund Case expenses "were incurred solely to ensure that Idaho Power would not be precluded from receiving refunds that might ultimately be ordered by the FERC." Tr. at 3147-49. Idaho Power contends its legal fees were paid to a law firm to represent its interests, and that IDACORP Energy hired a separate law firm to protect its interests. Tr. at 3149. Mr. Gale stated it is not seeking reimbursement of any legal expenses to defend IDACORP Energy, and that "the legal expenses in question were incurred to preserve potential benefits for utility customers." Tr. at 3151.

We believe the Company prudently acted to ensure that its ratepayers would be able to receive any potential refunds that may have resulted in these cases. That said, there is no reason to believe the entire amount of defending against these cases should be included in the test year as if the same amount will be incurred each year into the future. Because this litigation was unusual with its relationship to trading activities, the Commission finds it appropriate to reduce test year litigation expenses by the entire amount of $352,544. Although these particular legal fees are not recoverable, the majority of legal costs incurred in 2003 remain in the test year expenses for recovery.

Company witness Gale testified "if the Company knows it will be unable to recover its legal expenses incurred to pursue these refunds, it would be logical for the Company to cease actively participating in the cases and thereby reduce its exposure to unrecoverable legal expenses." Tr. at 3151. The Commission assumes that the Company will act in good faith to protect the interests of its ratepayers and shareholders, both of whom have a stake in proceedings involving power costs due to the PCA's 90/10 sharing mechanism. We would be extremely concerned if Idaho Power failed to effectively advocate for ratepayers who have no other representation in such proceedings. Denial of legal expenses for the Refund Cases in this Order in no way minimizes their importance; it merely recognizes that the regulatory accounting system does not permit inclusion of unusual expenses in a test year for ratemaking purposes.

8. Adjustments to Property and Liability Insurance Expenses.

Idaho Power proposed two increases in the test year expenses for property and liability insurance. Several insurance policies will expire during 2004, and the Company anticipates renewing the policies at higher premiums. Idaho Power proposes to increase test year expenses by the amount of additional insurance costs it claims are known and measurable to occur in 2004. The second adjustment the Company proposes is to annualize the new insurance costs so the total increased amount is collected each year in the future. Tr. at 528. Thus, Idaho Power proposed to add insurance costs for 2004 that are $364,014 higher than actually occurred in the test year, and then add an additional $384,586 to annualize the higher costs for recovery in future years. *Id.*; Tr. at 559.

Staff recommended removal of both insurance expense adjustments included in the test year by Idaho Power. Staff witness Holm argued that the amount of increase is not known or measurable, "it is simply an estimate of the new policy costs that may go into effect sometime during 2004." Tr. at 1412. According to Staff, Idaho Power stated that insurance coverage amounts might change; some may increase while others decrease. *Id.* Mr. Holm recommended removing Idaho Power's expense adjustment for higher insurance costs it anticipates will occur in 2004, because "the costs of the policies are not known at this time; they are simply estimated."

Id. For the same reason, Staff recommended the annualizing adjustment also not be allowed. Tr. at 1414.

The Commission finds that the Company-proposed increases to test year expenses for additional insurance costs are speculative and not based on known and measurable charges. Accordingly, the Commission will remove from the test year expenses the $748,600 Idaho Power added for increased property and liability insurance.

9. Adjustments to Management Expenses.

Staff presented Revised Exhibit 111 showing a recommended reduction of $63,291 to test year expenses for management personnel costs. Most of the expenses Staff would remove were for travel and expenses for Edison Electric Institute (EEI) conferences. Tr. at 1519. Other expenses included costs for meetings with politicians and lobbyists, green fees at golf courses, liquor store purchases, wine purchases, and excessive meal expenses. *Id.* Company witness Gale conceded that Staff's audit uncovered some items that were inappropriately included in test year expenses, but argued "the bulk of these expenses are legitimate." Tr. at 3146-47. Idaho Power stated its membership in EEI is a bona fide business expense of the Company, and that Idaho Power must be able to communicate with legislators and lobbyists "concerning important matters impacting both the Company and its customers." Tr. at 3147.

The Commission finds that some of the services EEI offers its members, such as education on industry issues and management training, are legitimate business-related expenses. Therefore, the Commission finds it just and reasonable to adopt only one-third of Staff's proposed expense reduction for inappropriate expenditures. We are convinced this level of adjustment will ensure that ratepayers are funding only those activities that are legitimate. Accordingly, test year expenses relating to management expenses will be reduced by $21,097.

10. Intervenor Funding Amortization.

Idaho Power included in the test year operating expenses the amounts it was required to pay intervenors in two separate cases in 2003. Intervenor awards were granted to the Land and Water Fund in Case No. IPC-E-01-16 in the amount of $4,956, and to the Irrigators in Case No. IPC-E-03-5 in the amount of $5,335. Staff witness Holm recommended these amounts be amortized and collected over five years, rather than allowing the Company to recover them "year after year until the next rate case." Tr. at 1445. As an alternative to a five-year amortization, Staff suggested the PCA could be used to allow a one-time recovery of the intervenor amounts.

Id. In rebuttal testimony, Company witness Gale suggested the PCA "is the perfect tool to recover intervenor funding amounts." Tr. at 3160.

Both Staff and the Company agreed that intervenor funding costs should be recovered just once and suggested different methods to achieve that end. We find it reasonable to place $10,291 of intervenor funding amounts in the 2005-2006 PCA for recovery in rates. Although we try to avoid unduly complicating the PCA, the Commission finds that PCA recovery of this small monetary amount will: (1) direct the costs to the customer classes that benefited from the intervention, (2) ensure that the amounts will only be recovered once, and (3) minimize interest accumulating until the amounts are fully recovered.

11. Additional Income Tax Assessment.

Idaho Power requested $2.9 million for additional tax payments made for the 1998-2000 audit cycle. Rather than collect this three-year amount each year in test year expenses, Staff supported use of a three-year average of the additional tax payments. This would decrease $1,960,529 from the federal tax test year expense and add $55,846 to the state tax test year expense. Tr. at 1440-42.

In its rebuttal testimony, Idaho Power noted that the Commission previously ordered that any income tax deficiencies actually paid during the test year should be included in the regulatory tax expense as set forth in Order No. 17499. Tr. at 2947-48. Moreover, the Company argued this was fair because it did not include deficiencies from previous audit cycles. Tr. at 2915.

The Company is correct that more than 20 years ago the Commission stated it "would allow the Company to recover as a tax expense any contingency actually paid in the year that it is paid." Order No. 17499 at 24. This language regarding the method of treatment was clearly not optimal. Ratepayers should pay the amount of the tax deficiencies once, not the entire three-year deficiency every single year. If the Commission implemented the Company's proposal, ratepayers would pay more than the actual tax expense. That would create an illogical and unreasonable ratemaking result. Because the Company's three-year audit cycle allows for the possibility of tax deficiencies every third year, the Commission finds it reasonable to average the additional tax payments over a three-year period. This symmetry between tax expense and collection in rates will allow the Company to recover its legitimate tax costs while minimizing the potential for over-collection.

12. Low Income Weatherization Assistance.

In its Application, Idaho Power's expenses included low-income weatherization assistance (LIWA) payments to Community Action Partnership (CAP) agencies at their current level of approximately $0.2 million per year. LIWA's services enable low-income families to permanently reduce their energy bills by making their homes more energy efficient. Three major LIWA funding sources for the CAP agencies are the U. S. Department of Energy (DOE), the U.S. Department of Health and Human Services, and Idaho Power. Tr. at 2105. The Bonneville Power Administration also contributes funds to the CAP agencies for LIWA, both directly and indirectly through utilities in its Conservation and Renewable Discount program, as do PacifiCorp and Avista Utilities. Thus, each CAP agency providing weatherization services in Idaho receives funding for LIWA from three to five agencies and utilities.

The Community Action Partnership Association of Idaho (CAPAI), represented by Ken Robinette and Teri Ottens, requested that Idaho Power's funding level be increased to $1.2 million per year from the current level. Tr. at 2124. CAPAI said $1.2 million would fully fund 440 homes per year. *Id.* The Northwest Energy Coalition, represented by Nancy Hirsch, also offered evidence and arguments supporting increased LIWA funding. Tr. at 2186-94.

CAPAI also requested that Idaho Power's contract allow the CAP agencies to submit their reimbursement requests to Idaho Power for the full amount of cost-effective work completed as determined by DOE's energy audit. Tr. at 2129. Currently CAP agencies can request only 50% of the cost of weatherizing a house from Idaho Power. Tr. at 2124, 3097. CAPAI argued that removing the 50% matching requirement would allow the CAP agencies to "...maximize their leveraging of federal and private [utility] funds." Tr. at 2129.

Finally, CAPAI requested that Idaho Power's administrative cost allowance for CAP agencies be increased from $75 per house weatherized as set in 1989 to $150 per house. Tr. at 2130. CAPAI said its projected administrative costs in 1998 were $146 per house. Tr. at 2122.

On rebuttal, Idaho Power opposed funding the full costs of the weatherization jobs and argued that the 50% matching requirement allows Idaho Power opportunity to assure that its customers' funds are used effectively. Tr. at 3097-99. The Company said it was willing to consider: (1) increasing the CAPs' administrative cost allowance, (2) reducing the savings to investment ratio (SIR) from 1.1 to 1.0, and (3) investigating its LIWA funding level. The Company indicated, however, that the rate case proceeding was not the appropriate place to consider these changes and instead suggested that CAPAI's proposals be addressed outside the rate case during the preparation of next year's contracts and/or through the Company's Energy Efficiency Advisory Group. Tr. at 3097-3101.

The Commission believes that funds devoted to LIWA are a wise investment that will benefit all Idaho Power ratepayers not just those who experience reduced power bills. Tr. at 1194, 2188-89. Increased LIWA funding can provide significant benefits in terms of lowering uncollectables and creating permanent load reduction. The record reflects that in past years LIWA has run out of funds mid-year in its efforts to achieve these ends. Tr. at 2124.

The Commission finds it just and reasonable to increase Idaho Power's annually expensed LIWA payments to CAP agencies by $1 million to approximately $1.2 million for each of the next three years, effective coincident with the rate increases authorized by this Order. The approximately $1.2 million annually shall include CAP agency administrative costs, but exclude any funds that Idaho Power may pass through to LIWA from other sources such as BPA. These dollars are to be booked and tracked in a separate balancing sub-account and paid directly to LIWA's administering agencies as projects are completed. Any unpaid funds shall carry over and be available in the next year. Furthermore, these funds are to be used only within Idaho Power's service territory and cannot be used to divert funds that otherwise would have been used within Idaho Power's territory. To this end, CAP agencies shall administer these funds using the historical allocation of LIWA funds as a basis to demonstrate that these funds were not used to divert other resources. If the allocation of other funding sources changes compared to historical allocations, we expect appropriate explanations will be included in the CAPAI's reports to Idaho Power and that Idaho Power will include these explanations in its reports to the Commission.

We also find that it is reasonable to increase the CAP administrative costs and suggest that $125 might be the appropriate amount going forward based on the 52% consumer price index increase since 1989. We believe this issue as well as whether the CAP agencies should be allowed to submit reimbursements up to the full cost of weatherizing a home, whether the SIR should remain at 1.1 or revert back to 1.0, and other program design changes should be negotiated between Idaho Power and CAPAI. Furthermore, we believe Idaho Power's proposal to have its EEAG review these issues is a valid one. We expect Idaho Power to file a report with the Commission at the conclusion of this process providing details and explanations of its LIWA program changes.

In addition, Idaho Power shall be required to file an annual LIWA report with the Commission. This report shall be separate from its annual demand side management (DSM) report, although at least a synopsis of the LIWA report should be included in the DSM report. The LIWA report should include, but is not necessarily limited to: the number of homes weatherized by county, a projection of homes to be served in the future, the cost per home served, a comparison of administrative costs to funds actually spent on homes weatherized, some detail of weatherization measures installed, associated energy savings, and overall cost-effectiveness. Idaho Power shall notify the Commission within 60 days of this Order's issuance of an appropriate date to file its annual report to provide the best available data. To continue receiving these funds beyond June 1, 2007, CAPAI must file an application to extend LIWA funding in early 2007. Depending upon the results of the annual reports and the three-year review in 2007, the Commission reserves the right to discontinue the LIWA funding authorized by this Order.

13. Income Tax Expense.

Idaho Power requested the Commission grant an effective tax rate of 32.795% for federal and 5.9% for state taxes. Tr. at 580. However, Staff argued it was more appropriate to average the federal and state income tax rates over five years, producing a 25.24% federal and 5.62% state tax rate for ratemaking purposes. Tr. at 1438. According to Staff, its proposal recognizes the higher tax expense ratepayers will pay in future years when the tax timing turns around. The Company chose to use a federal tax methodology where it can expense costs that were formerly capitalized. In addition, Idaho Power used the flow-through method for the tax change so ratepayers did not receive any benefit at the time the change was made. Tr. at 1430-40, 1471. This methodology change produced an immediate one-time tax refund or windfall for Idaho Power in 2002 of approximately $41 million. In exchange for that immediate tax refund, taxable income will increase over the remaining lives of the assets as repayment of the timing difference. Tr. at 1436. Staff's adjustment would also reduce deferred taxes by $352,405 and decrease the gross-up factor from 1.642 to 1.446. Tr. at 1439-40.

On rebuttal, Idaho Power alleged that Staff is trying to take advantage of Idaho Power's abnormally low effective tax rate in 2002 that resulted from a non-recurring deduction for an accounting method change. Tr. at 2941. Moreover, the Company believes Staff's adjustment would violate the normalization requirement of the IRS Code and constitutes retroactive ratemaking. Staff argued that its proposal would do neither of these things because its proposed five-year average would be applied prospectively to approximate the future effects of the tax methodology change and would be used only for ratemaking purposes. Staff Post-Hearing Brief at 8.

As we see it, in 2002 the U.S. Treasury essentially made a loan in excess of $41 million to Idaho Power that must be repaid in the form of higher future taxes. Had this been an outright gift to Idaho Power requiring no future obligation by ratepayers, this Commission could find it reasonable to adopt the Company's income tax arguments. Because this money was neither a gift nor a grant of funds, ratepayers are in the worst of all positions because they: (1) did not share the tax (loan) proceeds Idaho Power's shareholders received in 2002, (2) will have to repay more than $41 million in higher tax expense in future years, and (3) could be subject to a tax deficiency payment if the IRS determines that Idaho Power did not properly file the 2001 tax return that resulted from the tax methodology change (loan). This unfair outcome constitutes improper ratemaking without an adjustment to offset the higher tax expense ratepayers will pay in the future. Consequently, we adopt Staff's recommendation for a five-year average for the income tax test year expense to account for the increased taxes ratepayers will pay in future years. Although Idaho Power may have interpreted Staff's adjustment as seizing out-of-period revenues or as punishment for choosing the windfall over normalizing the methodology change, this adjustment merely achieves a neutral economic impact for Idaho Power and its ratepayers over time.

The Company has argued that a five-year average tax expense would result in a normalization violation. A normalization violation exists when tax benefits are flowed to ratepayers faster than the IRS allows. Company witness MacMahon testified, "the normalization rules require a legal minimum of tax expense to be provided in a regulatory proceeding in order to enjoy the benefits of accelerated tax depreciation and this legally required minimum has not been met by Staff's methodology." Tr. at 1920-21. The Commission has no desire to run afoul of IRS regulations and jeopardize the Company's use of accelerated depreciation. We do not believe a normalization violation will occur in this case where only the test year taxes are changed because tax benefits are not being passed through to ratepayers faster than IRS regulations allow. The full amount could have been flowed through to ratepayers in 2002 with the flow-through method. Passing it through now to customers for ratemaking purposes using a five-year average is slower than allowed, not faster. We also note that Idaho Power could have avoided this issue by normalizing the tax methodology change rather than flowing it through in a single year.

Idaho Power argues that it would be retroactive ratemaking to take into account previous extraordinary revenues or expenses that will not reoccur. Tr. at 2941-42. Because the tax methodology change has essentially caused the taxes paid from 1987-2000 to "reoccur" such that these amounts will have to be repaid in the future, our decision to use the five-year average to approximate this amount does not constitute retroactive ratemaking. This adjustment anticipates and reasonably attempts to rectify a future anomaly caused by the Company's decision. We are looking forward, not back. The five-year average, a methodology the Company has advocated for setting variable interest rates, is a well-established proxy that establishes tax expense using the past as an indicator of the future. Moreover, the five-year average will be re-evaluated when the Company files its next general rate case expected in the next "two to three years." Tr. at 3193.

Deferred taxes are created by timing differences that result when the Company takes tax benefits early that will have to be paid back later. Although Idaho Power claimed that Staff's tax proposal would decrease deferred taxes by $53 million in rate base, the record does not disclose how that number was calculated. Tr. at 2917. Although we recognize that the deferred tax amount to be adjusted could be higher than that proposed by Staff, there was not adequate information in the record to calculate a different number. Using the best information provided in this case, we believe it is just and reasonable to use Staff's deferred tax number and reduce deferred taxes by $352,405.

The gross-up factor is used to calculate income taxes on the projected revenue deficiency that results when newly authorized earnings exceed actual earnings. Because the gross-up multiplier impacts future earnings rather than those in the test year, we find it reasonable to use the Company's proposed 1.642 gross-up factor to avoid under-recovery of tax expense associated with incremental increased revenue resulting from this case.

14. Summary of Adjustments to Rate Base and Test Year Revenues and Expenses.

Considering all the evidence presented, and including all adjustments, the Commission finds just and reasonable total system operating expenses for the 2003 test year in the amount of $515,637,445, and total operating revenues in the amount of $618,503,239. After all adjustments, we find a 2003 total system rate base amount of $1,643,706,370 to be just and reasonable. The Idaho jurisdiction rate base is $1,519,924,799; Idaho operating expenses total $481,521,037, and Idaho operating revenues total $578,752,380 for the 2003 test year. Appendix 1 to this Order summarizes the Commission's findings on rate base and operating results for the test year.

CAPITAL STRUCTURE AND RATE OF RETURN

1. Capital Structure.

In its initial filing, Idaho Power estimated year-end 2003 balances for its capital structure of long-term debt, preferred stock and common equity for use in determining a return on rate base and overall rate of return, but recommended the Commission update the capital structure to reflect an actual year-end 2003 capital structure. Tr. at 474. Staff used the December 31, 2003 equity infusion to adjust the November 30, 2003 capital structure, recommending the Commission adopt a capital structure consisting of 51.38% long-term debt, 2.99% preferred stock, and 45.63% common equity. Tr. at 1826. Idaho Power in rebuttal testimony provided the actual year-end capital structure as 51.060% long-term debt, 2.969% preferred stock, and 45.971% common equity. Tr. at 2750.

The Commission finds Idaho Power's actual capital structure at December 31, 2003, as stated by the Company, to be appropriate for calculating the Company's overall rate of return. Our decision to use the actual year-end capital structure to determine the overall rate of return is consistent with Order No. 25880 issued in Idaho Power's last rate case proceeding in Case No. IPC-E-94-5.

2. Cost of Debt.

Idaho Power testified that its embedded cost of debt is 5.983%. Tr. at 475. Staff determined the Company's cost of debt to be 5.63% by adjusting the debt rate used by Idaho Power to reflect maturity of a fixed 8% interest mortgage bond and its replacement with 6% interest bonds. Tr. at 1826-27. Micron also restated Idaho Power's cost of debt in light of the refinancing of the mortgage bond, using a 5.7% interest rate, to reach a 5.839% cost of debt. Tr. at 2456. Staff's determination of the cost of debt also reflected a lower interest rate for the Pollution Control Bonds, which is a variable rate bond. Tr. at 1827. Staff used the 2003 year-end rate for the variable rate bonds, while Idaho Power used a ten-year average to establish the interest rate for variable rate debt. Tr. at 2754-56. Company witness Dennis Gribble testified, however, that the Company could support a five-year average to determine the interest rate for the variable rate bonds so long as that methodology is applied consistently in future rate cases. Tr. at 2756-57. During the hearing, Idaho Power also indicated it was appropriate to use the actual 5.5% interest rate now in place on the first mortgage bonds refinanced March 26, 2004 to calculate its cost of debt. Tr. at 2759-61.

The Commission finds the appropriate calculation of Idaho Power's cost of debt to be 5.769%. This figure includes the refinancing of the 8% Series First Mortgage Bonds in March 2004 at 5.5% with an all in cost of 5.6%. With regard to variable rate bonds, the Commission finds it reasonable to use a five-year average of the Bond Market Association (BMA) Municipal Swap Index in this case as the most appropriate measure of the variable rate for the Pollution Control Revenue Bonds outstanding. This BMA rate reflects that the interest rate varies while providing an averaging to reflect the lower rates currently and in the past few years. The use of this methodology is reasonable based on the evidence in this record. It does not constitute a guaranteed acceptance of this variable rate bond methodology in future rate cases as requested by Idaho Power in its rebuttal testimony. Tr. at 2756.

3. Cost of Preferred Stock.

Idaho Power testified its embedded cost of preferred stock used in the forecasted 2003 capital structure is 6.534%. Tr. at 482. Staff verified the Company's rate and used it in Staff's capital structure recommendation. Tr. at 1827. Accordingly, the Commission adopts 6.534% as the appropriate cost rate for preferred stock in determining the Company's capital structure and rate of return.

4. Cost of Common Equity Capital.

We turn next to a determination of the appropriate cost of common equity capital. The cost of common equity is primarily an attempt to quantify a rate of return required by investors for that particular investment. Idaho Power's witnesses testified that the possible range for its cost of common equity is 10.6% to 11.9%, and that 11.2% is "the minimum required rate of return considering the Company's overall management efforts throughout these last ten years." Tr. at 449 and 956. Staff witness Carlock concluded "the fair and reasonable cost of common equity capital . . . for Idaho Power is in the range of 9.5% - 10.5%." Tr. at 1827. Staff used a mid-point rate of 10% in calculating the overall rate of return. *Id.* Finally, Micron witness Peseau determined the appropriate range for Idaho Power's cost of common equity to be

8.4% to 10.6%, and recommended the midpoint rate of 9.5%. Tr. at 2454. Micron also pointed out that the Commission determined the appropriate cost of common equity for Idaho Power to be 11% in the Company's last rate case. Noting "investors' expected earnings on both bonds and stocks have dropped dramatically since 1994," Dr. Peseau testified "Idaho Power's request for an 11.2% return on equity, some 20 basis points higher than the Commission authorized in 1995, is unreasonable on its face." Tr. at 2454-55.

The Commission in its last Idaho Power rate case, Order No. 25880, summarized the different methodologies used to analyze and ascertain a fair rate of return on common equity capital. The Commission has relied primarily on the discounted cash flow method (DCF) and the comparable earnings method in previous rate cases, and we do so again in this case. Order No. 25880 at 21. A third methodology is a risk premium analysis, which begins with a low risk investment, such as government or utility bonds, and adds a premium based on the relative risk associated with a utility's stock. *Id.* The capital asset pricing model (CAPM) measures risk using the beta coefficient. The return on equity is measured in relation to the market as a whole. As markets change, new concerns develop in various financial circles related to the calculations used to determine the cost of equity. One such concern continues to be the measurement and proper use of Beta. This Commission has not focused on Beta or CAPM for determining the cost of equity; therefore any new concerns are not at issue in this case for this Order and will not be specifically addressed. We have evaluated the concerns addressed by the parties in this case and heard from the financial community associated with the determination of the growth rates and the use of accounting numbers in the era of accounting scandals. We are confident that by evaluating all the methods presented in this case and using each as a check on the other when setting the allowed rate of return, we have not focused our determination such that these concerns are an issue. The growth rate has been properly matched to the dividend yield in the DCF method and the comparable earnings using accounting data is being used as a check for reasonableness. The goal of each methodology is to ascertain a rate of return on common equity at a point sufficiently attractive that investors will consider purchasing common equity shares in the company. However, "the methods to evaluate a common equity rate of return are imperfect predictors of future performance," and "the rate of return on equity specified by a regulatory agency is but one factor considered by prudent investors when evaluating a utility's stock." Order No. 25880 at 20-21.

Idaho Power's cost of capital witness Dr. William Avera described the DCF model he used to assess the Company's cost of equity. Essentially, the DCF model estimates "the cash flows investors expect to receive from the stock in the way of future dividends and capital gains" and, given the current price of the stock, calculates the investors' required rate of return. Tr. at 992. Put another way, "the cash flows that investors expect from a stock are estimated, and given its current market price, we can 'back-into' the discount rate, or cost of equity, that investors presumptively used in bidding the stock to that price." *Id.* Dr. Avera did not apply the DCF model directly to Idaho Power because as a wholly owned subsidiary of IDACORP it does not have publicly traded stock, and because the Company last year cut its common dividend payment. Tr. at 995. Instead, Avera applied the DCF analysis to a "reference group of other electric utilities composed of those companies included by Value Line in their Electric Utilities (West) Industry group." Tr. at 995-97. Avera eliminated six companies from the proxy group, leaving eight utilities "engaged in electric utility operations in the western region of the U.S." Tr. at 997.

Avera's first step in implementing the DCF model was to determine the expected dividend yield for the companies in the proxy group. That is accomplished by dividing each company's expected dividend by the company's stock price. Tr. at 1004-05. Avera concluded the dividend yields for the eight companies range from 3.2% to 6%, with the average being 4.4%. Tr. at 1005. The next step in the DCF methodology is to estimate investors' long-term growth expectations for the company being evaluated. Tr. at 1004. Avera provided growth expectations for the proxy group published by four different security analysts, showing growth rates of 2.7% to 5.5%. Tr. at 1011. Avera also looked at historical growth in earnings, showing growth rates of 7.3% during the last 10 years, and 8.1% during the last 5 years. Tr. at 1012. Finally, Avera looked at the relationships between retained earnings and earned rates of return as an indication of the growth investors might expect from the reinvestment of earnings within a firm, the review of which yielded an average expected growth rate of 4.7% for the proxy group. Tr. at 1013-15. Avera concluded "investors currently expect growth on the order of 5.0 to 7.0 percent for the average firm in the electric utility proxy group." Tr. at 1015.

The final step in the DCF model is to combine the dividend yield and the estimated growth rate to arrive at an estimate of the company's cost of equity. Tr. at 1005. Avera added his 4.4% average dividend yield with the 6% midpoint of his expected growth range to determine a DCF cost of equity for the proxy group of 10.4%. Tr. at 1015.

Avera also used a risk premium analysis to evaluate Idaho Power's cost of equity. Because the Commission gives more weight to the DCF analysis, we will not attempt to explain in this order the application of the risk premium analysis. Avera concluded the yield on public utility bonds in August 2003 implied a current equity risk premium of 4.39% for electric utilities. "Adding this equity risk premium to the August 2003 yield on single-A public utility bonds of 6.79 percent implies a current cost of equity for Idaho Power of approximately 11.2 percent." Tr. at 1023-24. Avera used an alternate method to determine the risk premium to estimate a current cost of equity of approximately 11.7%. Tr. at 1027. Avera concluded his DCF model and risk premium analyses produced a range for Idaho Power's cost of equity of 10.4% to 11.7%, to which he then added 20 basis points in flotation costs to increase his estimated range for Idaho Power's cost of equity to 10.6% to 11.9%. Tr. at 1032. "Flotation costs" cover the expenses of issuing common stock in the market.

Micron's cost of common equity witness was Dr. Dennis Peseau. Dr. Peseau criticized Avera's analyses because they "suffer from stale capital market data," and testified that "changing capital markets have changed the inputs to all of Dr. Avera's analytical methods." Tr. at 2438 and 2442. According to Dr. Peseau, "Dr. Avera developed his analyses using capital market information from last summer, and both debt and equity markets have improved enormously since that time." Tr. at 2444. If Dr. Avera's cost of equity analyses are replicated using his methods "exactly with no changes other than updated numbers," according to Dr. Peseau, Idaho Power's cost of equity is within a range of 9.7% to 10.6%. Tr. at 2443.

Dr. Peseau also proposed specific corrections to Dr. Avera's risk premium and DCF analyses. For example, Dr. Peseau noted that Dr. Avera used an average public utility bond yield in part of his risk premium analysis, and the yield on a single A- rated bond in another part. Tr at 2444. Noting that "most Idaho Power debt instruments carry the A- rated credit standing," and the "point of these exercises is to solve for Idaho Power's risk premium, not that of the average utility," Dr. Peseau claimed "Dr. Avera's substitution biases his estimates upward." *Id.* Using the same bond yield throughout the risk premium analysis reduces Dr. Avera's cost of equity result from 11.2% to 10.59%. Tr. at 2445.

Regarding Dr. Avera's DCF analysis, Dr. Peseau testified Dr. Avera's DCF "methodology is not unreasonable, but its implementation is flawed." Tr. at 2448. Dr. Peseau claimed Dr. Avera's selection process for the proxy group of utility companies "high grades the proxy group," and that a second problem "is that the group is so small that there is a serious risk of sampling errors." Tr. at 2448-50. Dr. Peseau recommended adding back in to the group the four dividend paying companies that Dr. Avera "arbitrarily removed," and rejecting altogether Dr. Avera's five- and ten-year historical calculations he used to determine a yield component as unreliable. Tr. at 2450-51. With the corrections Dr. Peseau recommended to Dr. Avera's analyses, Dr. Peseau produced cost of equity results for Idaho Power that range from 8.4 % to 10.6%, with a midpoint of 9.5%. Tr. at 2453-54.

Terri Carlock, who used the DCF and Comparable Earnings methods to determine the appropriate cost of equity, presented the Staff's evidence on Idaho Power's cost of equity. Tr. at 1820. Applying the DCF model directly to IDACORP, and thus Idaho Power, rather than to a proxy group of utility companies, Carlock determined a cost of equity range of 7.4% to 8.8%. Tr. at 1825. Carlock's Comparable Earnings analysis produced a cost of equity range for Idaho Power of 10% to 11%. Tr. at 1827. Carlock concluded that "the fair and reasonable cost of common equity capital . . . for Idaho Power is in the range of 9.5% to 10.5%." *Id.*

In his rebuttal testimony, Dr. Avera identified perceived weaknesses in Staff's cost of equity analysis and responded to Dr. Peseau's criticisms of his cost of equity analyses. Dr. Avera's primary criticism of Carlock's analysis is that, "because she restricted her DCF analysis to a single company – IDACORP – Ms. Carlock's results are extremely susceptible to measurement error and bias." Tr. p. 1063. Carlock explained on cross-examination that she utilized the proxy utility group DCF analysis to verify the reasonableness of using IDACORP for the primary DCF analysis. Tr. at 1836, 1851. She also clarified that flotation costs were included in the dividend yield component of her DCF. Tr. at 1832-33, 1835. Avera also criticized Carlock for not applying the risk premium approach, stating that "no single method or model should be relied upon to determine a utility's cost of equity because no single approach can be regarded as wholly reliable." However, Dr. Avera failed to acknowledge that Carlock had also performed a comparable earnings analysis. Tr. p. 1066-68.

Dr. Avera argued that Dr. Peseau did not do an independent analysis but merely "updated" the dividend yield in Avera's DCF model while ignoring the equation's growth rate.

Tr. at 1076. Dr. Avera also criticized Dr. Peseau's remaining modifications as ignoring historical trends in earnings growth in applying the DCF model, using alternative bond yields to apply Dr. Avera's risk premium approaches, substituting a lower market return in the CAPM, and ignoring the flotation cost adjustment. *Id.* Finally, Dr. Avera denied that his risk premium approaches had inconsistencies that biased the results upward. Tr. at 1081.

As part of our determination of the appropriate return on equity, the Commission will consider information regarding the risk an investor may consider in deciding to purchase a utility stock. That may include information regarding the efficient management of the utility. Each of the cost of capital witnesses discussed risks associated with utilities in general, and Idaho Power in particular, that investors may consider when deciding whether to purchase IDACORP stock.

For example, Idaho Power witnesses Dr. Avera and Gribble testified that investors are likely to consider the impact of industry uncertainty stemming from western power market crises, the Enron meltdown, the Midwest/northeast blackouts, counter party credit erosion, environmental pressures, and inflation on the required rates of return for utilities. Tr. at 451, 965–79. They also believe Idaho Power is particularly susceptible to risks created by low streamflows for hydroelectric generation, wholesale market volatility, hydroelectric relicensing, and regulatory uncertainty. Tr. at 452-63, 1039-44, 2746-49.

Micron witness Dr. Peseau argued that Dr. Avera's observations are accurate enough but present "too bleak a picture of the industry." Tr. at 2440. He explained that the overwhelming majority of the Nation's electric utilities have weathered these disasters and are now strengthening their core businesses in a nearly ideal economic environment. *Id.* Although problems and uncertainties still exist in the electric industry, these are not unique to electric utilities. *Id.* Dr. Peseau also suggested that investors do not widely share Dr. Avera's "doom and gloom" outlook for Idaho Power or the industry, particularly given that Idaho Power shareholders received a rate of return in excess of 40% in the last year over the 2003 year when including both price appreciation and dividend yield. Tr. at 2441.

Staff witness Carlock testified that competitive risks are limited for Idaho Power because the demand for utility services is relatively stable as compared to unregulated or other utility industries due to its low-cost power and customer mix. Tr. at 1822-23. As compared to most other electric companies, Idaho Power's competitive risks are less because of its low-cost source of power and relatively low retail rates. *Id.* Ms. Carlock also believes that while the

Company has less investment risk due to power supply cost recovery in the PCA mechanism, IDACORP's main risks are primarily due to non-regulated operation. *Id.*

The evidence in this case supports a rate of return on common equity for Idaho Power ranging from 8.4% to 11.9%. We find Idaho Power's reasonable required rate of return on common equity to be 10.25%. When this rate is placed in the calculation of the Company's cost of capital, the result is an overall rate of return of 7.852%. This overall return also reflects the impact that low interest rates have on the cost of equity.

In authorizing a 10.25% return on common equity, this Commission acknowledges its desire to maintain Idaho Power as a financially viable utility with credit ratings at or above the current level. With the wind down of IDACORP Energy, IDACORP, and Idaho Power specifically, are sheltered from many risks that impact other utilities. Idaho Power's annual PCA mechanism continues to limit the risk of the Company. Idaho is not likely to have deregulation risks like those experienced by other states and continues to have low power costs. The Idaho Commission's authority over security issuances indirectly "ringfences" or limits the Company's financial and/or bankruptcy risk exposures. These factors may not eliminate Idaho Power's risks, but they minimize them. The overall impact of this Order supports plant investment, provides a return on equity of 10.25% in a low interest rate environment, and improves Idaho Power's revenue stream from the current level.

The use of this cost of common equity, together with the costs of debt, preferred equity and capital structure previously found, yields the following overall return for rate base:

Component	% of Capital Structure	Cost	Weighted Cost
Debt	51.060%	5.769%	2.946%
Preferred Equity	2.969%	6.534%	0.194%
Common Equity	45.971%	10.250%	4.712%
TOTAL	100.000%	--	7.852%

CALCULATION OF REVENUE DEFICIENCY

With the Idaho rate base, revenue requirement and return on common equity established, the Commission determines the Idaho revenue requirement with the following calculation:

Rate Base	$1,519,924,799
Rate of Return	7.852
Revenue Requirement	$119,344,495
Adjusted Net Operating Income	$103,918,528
Income Deficiency	$15,425,967
Incremental Tax Multiplier	1.642
Revenue Deficiency	$25,329,438
Percent Increase Required	5.23%

JURISDICTIONAL SEPARATIONS

Compared to previous Idaho Power rate cases, there is relatively little dispute in this case regarding the Company's jurisdictional separations methodology. The jurisdictional separations methodology, referred to as the 12 coincident peak (12 CP) methodology, is used to allocate total electric system costs to the Idaho, Oregon or Federal Energy Regulatory Commission (FERC) jurisdictions. The FERC jurisdiction is comprised of Idaho Power's wholesale sales of energy to other utilities. The Company used the same jurisdictional separation methodology it has used for more than 25 years to allocate the Company's annual expenses among the jurisdictions it serves. Tr. at 567. Staff and some intervenors recommended the Commission approve Idaho Power's jurisdictional separations methodology, and no party objected to the Company's jurisdiction separations results.

On this record, the Commission finds that the 12 CP methodology the Company used to separate system costs between the Idaho, Oregon and FERC jurisdictions is reasonable and appropriate. The 12 CP jurisdictional separations study results in an Idaho system revenue requirement allocation of $509,394,816.

COST OF SERVICE METHODOLOGY

Once total Idaho jurisdictional costs are determined with the jurisdictional separations study, the next step is to allocate those costs among the different customer classes served by Idaho Power. This allocation of costs is accomplished with a class cost of service study, which is similar to the jurisdictional separations study in assigning cost responsibility. However, as the Commission has cautioned in past Idaho Power rate cases, a cost of service study is not a perfect tool for assigning system and service costs to customer classes. The Commission relies on a cost of service study as a starting point to allocate costs, "but in the end we must, and do, consider other factors such as rate continuity, equity and proportionality." Order No. 25880 at 27.

Idaho Power proposed use of a weighted 12 coincident peaks (W12CP) cost of service study to assign costs to customer classes. The Commission used this methodology in Idaho Power's last three rate cases. Tr. at 750-51, Order No. 25880 at 27. The W12CP methodology assigns a value (weighting factor) to each calendar month based on system capacity and power supply costs needed to meet monthly peak energy demands. Staff used the Company's cost of service study to allocate Idaho jurisdiction costs to the various customer classes, but also performed two other studies as a check on the W12CP results. The other two studies by Staff were variations on the W12CP methodology. In one, Staff weighted the month of June at zero; in the second, Staff used a traditional unweighted 12 CP methodology. Tr. at 1617-18. Staff performed the additional studies because the Company study showed that a substantial rate increase was needed to bring the irrigation class to full cost of service, and Staff "wanted to know how sensitive class allocations, especially irrigation class allocations, are to allocation factor changes." Tr. at 1618. Using Staff's test year revenue requirement, Staff's cost of service studies showed required rate increases to bring the irrigation class to full cost of service range from 29.1% (unweighted 12 CP) to 47.2% (W12CP). Tr. at 1617-18. With the Company results validated by the studies, Staff recommended the Company's W12CP cost of service study be accepted as the starting point to allocate costs to customer classes. Tr. at 1620-21.

With the exception of the Irrigators, the intervenors that addressed the Company's cost of service study either recommended its use or did not object to it while offering suggestions for improvement. For example, the Industrial Customers noted that peak energy demands are used to determine allocation factors in the cost of service study, and that different customer classes may react differently to peak load under different weather conditions. Tr. at 1342-43. The Industrial Customers witness Dr. Reading suggested the Company "investigate how peak loads react to weather conditions and what impact that it may have on inter-class allocations."

Tr. at 1344. DOE witness Goins also recommended a change in the way Idaho Power determined allocation factors, specifically in the way the Company classified hydro and steam production costs as demand- and energy-related. Tr. at 2233-36. DOE nonetheless recommended the Commission accept Idaho Power's cost of service methodology, testifying that although "class responsibility cannot be determined with certainty . . . IPC's cost study reflects a reasonable approximation of class cost responsibility." Tr. at 2231, 2255.

Other than the Irrigators, Micron expressed the greatest concern with Idaho Power's W12CP methodology. Micron witness Dr. Peseau testified that "Idaho Power's cost of service study is consistent with sound costing methods and prior Commission orders, with one very significant exception." Tr. at 2456. The exception Micron identified is in the generation and transmission demand allocators, where Idaho Power averaged weighted 12 CP allocators with unweighted monthly allocators. Tr. at 2458. Micron performed a cost of service study using weighted 12 CP allocators for generation and transmission costs rather than Idaho Power's average of monthly allocators. The result is that, "the cost of service for all classes other than the irrigation class are lower in [Micron's] study compared to the Company's, and the cost of service for the irrigation class is higher." Tr. at 2464.

Not surprisingly given the results of the study, the Irrigators' witness Yankel objected to Idaho Power's cost of service study, describing it as "fatally flawed and cannot be relied upon to give accurate results." Tr. at 2558. The Irrigators discussed difficulties in accessing the cost of service computer model, problems in the way Idaho Power weighted the coincident peaks in the 12 months and in the use of marginal cost weighting factors, and problems with data Idaho Power used for modeling inputs. In addition, the Irrigators suggest that new customer growth in other classes have caused the increased costs while the irrigation class has remained virtually unchanged. Mr. Yankel recommended that more costs be placed on the growing classes that cause them rather than placing an increased burden on the irrigation class. Tr. at 2620-22. Yankel asked the Commission to approve an equal percentage "across the board [rate] increase to all customer classes," rather than approve rates based on an assignment of costs as derived from Idaho Power's cost of service study. Tr. at 2599.

As we have in past rate cases, the Commission finds the W12CP cost of service study is the appropriate starting point to allocate costs to customer classes. The Industrial Customers, Micron, DOE, Staff, Kroger, and AARP all agreed that Idaho Power's study was appropriate for allocating costs. Consequently, we find that the W12CP cost of service results reflect "a reasonable approximation of class responsibility" and thus provide a measure of relative revenue responsibility among the customer classes. Tr. at 2255, Order No. 25880 at 27.

While we find Idaho Power's study appropriate for allocating costs in this case, we are not determining the soundness of each component or input to the methodology. In fact, we believe the Irrigators and other parties have raised serious legitimate questions regarding the cost of service components and that they deserve additional investigation. Therefore, we open a separate docket for the purpose of evaluating cost of service issues raised in this proceeding. Specifically, we direct Staff and interested parties to evaluate appropriate issues through a series of workshops (as needed), including: (1) how best to determine and weight monthly generation and transmission allocators, (2) how to most accurately capture coincident peak demand responsibility, and (3) whether new growth is properly covering its cost of service. We expect consensus investigation results and recommendations to be documented in a final report and submitted to the Commission no later than February 28, 2005.

With respect to the issue of new growth and how its cost flows through the cost of service study, we also expect the parties to submit recommendations regarding any needed changes in Idaho Power's line extension rules that are identified by the investigation. Once the cost of service investigative report is received, the Commission can then determine how best to proceed in addressing any recommended line extension tariff changes.

CLASS REVENUE ALLOCATIONS

Accepting the W12CP cost of service results as a starting point, the Commission must determine the appropriate revenue requirement to be recovered in the rates of the different customer classes. The summary results of the W12CP cost of service study using the Commission established revenue requirement is shown in Appendix 2.

A significant hurdle to implementing rates for each class in line with the results of the cost of service study is the size of the increase the study assigns to the irrigation class. For example, Idaho Power's cost of service study, using the Company's proposed revenue requirement, showed an increase of more than 67% would be required to move the irrigation class to full cost of service study results. Tr. at 1356. Staff's cost of service study, using the same W12CP methodology but a greatly reduced Idaho jurisdiction revenue requirement, indicated a rate increase of approximately 47% to bring the irrigation class to full cost of service. Tr. at 1707.

Most of the witnesses testifying on class revenue allocation addressed the size of the rate increase it would take to move the irrigation class to match the cost of service study results. Idaho Power proposed to cap the rate of increase for the irrigation class at 25%, and Staff suggested the irrigation customer rate increase be capped at 15%. Tr. at 1256, 1679. DOE recommended the irrigation class be given a rate increase twice as large as the overall average system increase. Tr. at 2243. AARP recommended annual increases in the irrigation rates for four years after new rates are implemented. The example AARP provided, using Idaho Power's cost of service results, would initially increase the irrigation rates 25% as the Company proposed, and then increase rates 4% each year for the next four years. Tr. at 2354-56. Kroger recommended the Commission adopt a rate plan that moves the irrigation class rates one-third of the way to full cost of service using annual increases for three years after implementation of new rates in this case. Using Idaho Power's cost of service results, Kroger's recommendation would increase the irrigation rates 25% and then annually for three years by 4.7%. Tr. at 2053-54. Micron recommended the irrigation class be given the same percentage rate increase each year for the next five years. Using Idaho Power's proposed revenue requirement, the irrigation class would receive an annual rate increase of 18.6% for the next five years under Micron's proposal, but would see a rate reduction of 28.77% in the sixth year. Tr. at 2471-72. United Water summarized the different recommendations regarding the irrigation class revenue requirement, and suggested the Commission give serious consideration to Micron's proposal. Tr. at 2289-91.

Using the Commission-determined Idaho jurisdictional revenue requirement, the cost of service study indicates a rate increase of 48.7% for the irrigation customers to move to full cost of service. A number of witnesses testified to the importance of moving the irrigation rates closer to full cost of service to avoid unfairness to the remaining customer classes. For example, United Water noted that under Idaho Power's revenue allocation proposal, rates for Schedule 9 customers are 5.4% higher than they would be if the irrigation rates were at full cost of service. Tr. at 2285. United Water witness Healy also testified that residential customers receive the heaviest burden from the irrigation class revenue requirement. "United's residential customers are paying for the [irrigation] subsidy first through their electric rates and then again through their water rates, which include United's electric power costs." *Id.* AARP witness Power testified that shifting part of the irrigation costs of service to residential customers and other businesses reduces the expenditures the households can make in local businesses, and burdens other businesses with higher costs so that one type of business can have lower costs. Tr. at 2350-51. Micron witness Dr. Peseau testified that a revenue subsidy is created when electricity to a class of customers is under-priced compared with the actual cost of serving the class "because, under normal ratemaking, any shortfall to a class is made up by overcharging some or all of the remaining customer classes." Tr. at 2466. DOE witness Goins noted that Idaho Power proposes to "overcharge" other customers to make up the shortfall in revenue assigned to the irrigation class, and testified that "these interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class much closer to cost of service than IPC has proposed." Tr. at 2241-42. Staff witness Schunke proposed allocation of revenue requirement to the irrigation class at less than cost of service, which means "the revenue responsibility of the irrigation class is reduced by over $19 million and this amount is reallocated to the other customer classes." Tr. at 1679.

Not all the testimony in the record supported moving the irrigation class to full cost of service. The Commission received public testimony from irrigators who were concerned with the size of the proposed irrigation rate increase. Many individual irrigators testified the 25% irrigation rate increase requested by the Company, or even the Staff-proposed 15% increase on top of the rates they paid in 2003, would drive them or other irrigators out of business in the current farming economic climate. Tr. at 61, 67, 94, 145, 180, 208, 234, 241, 257, 1927-29, 2008. Individual irrigators also questioned how such a large percentage of costs could be allocated to the irrigation class. For example, a member of the Bell Rapids Board of Directors from Buhl doubted the need for irrigators to "pay a 15% increase that is four times the increase of any other ratepayer." Tr. at 180. An Oakley director of the Idaho Ground Water Users Association testified that most of the increase in peak power consumption has resulted from residential use. Thus, irrigators should not be expected "to pick up that liability where we've been stable for 30 [or] 40 years in our development." Tr. at 256. The Chairman of the Power County Commissioners testified, "it appears that rate increases are being unfairly targeted at irrigation even though their usage hasn't gone up measurably." Tr. at 45. He suggested that "large residential growth in some parts of the state" likely created the need "for the increased production and for handling the spikes in power usage." *Id.* An American Falls irrigator further testified that because Idaho Power's line extension tariffs are not adequate to fund growth, "farmers in small towns [are being asked] to subsidize expansion in urban areas." Tr. at 66.

Given the less than perfect results from cost of service studies, and the other considerations that are part of revenue allocation decisions, we find that the revenue requirement assigned to the irrigation class should be less than indicated by the cost of service study. The Commission has often stated that considerations such as rate stability and proportionality justify limiting the amount of the rate increase to any class of customers. Cost of service studies have consistently shown, however, that the irrigation class is paying rates significantly below the cost to serve it relative to the cost to serve other classes. We stated in the last Idaho Power rate case regarding the irrigation customer rates that, although cost of service studies are not precise, "we think it important that cross subsidies among customer classes should be minimized." Order No. 25880 at 36.

We find that the rate increase for the irrigation class should not exceed 13.95%. The irrigation class increase approved by the Commission is more than twice the approved system rate increase, yet has a smaller dollar impact on irrigators than the options the parties recommended from the cost of service results. For example, Idaho Power proposed to increase the irrigation revenue requirement by over $15 million, while Staff recommended an increase in excess of $9 million. The following chart shows the affect of the Commission approved revenue increase for the irrigation class compared to the other recommendations:

Irrigation Base Rates	% Increase	Cents per kWh	$ Increase
Current Base Rates	--	3.726	--
Company-Proposed Base Rates	25.0%	4.650	$15,078,364
Staff-Proposed Base Rates	15.0%	4.285	$9,059,627
Commission-Ordered Base Rates	13.95%	4.246	$8,428,099

We also find that the remaining revenue requirement should be apportioned equitably among the other customer classes. The spread of the revenue requirement to the customer classes the Commission finds to be just, fair and reasonable is set forth in Appendix 3. No customer class subject to a rate increase in this case, experiences a revenue requirement greater than 5% above that indicated by the cost of service study. When deficiencies in the cost of service study identified by the various parties are considered in conjunction with the devastating effect a 100% move to cost of service could have on irrigators, we believe our decision is warranted and reasonable. We have directed the parties to investigate the various components of cost of service to provide more definitive information regarding appropriate cost responsibility for each class. Until that information is provided to us, we find an irrigation class percentage increase of more than twice the average increase for other classes in this case to be equitable.

RATE DESIGN AND TARIFF ISSUES

Idaho Power proposed numerous changes to rate design for the different customer classes, including renaming the fixed customer charge and significantly increasing it for most customers. The Company's proposal for large increases in the customer charge generated the most response from members of the public, and also was opposed by Staff and every intervenor that discussed it. In addition to increased customer charges, the Company also proposed to increase energy charges for every customer class in order to generate its proposed revenue requirement. Idaho Power also recommended the implementation of higher energy rates during the summer months for most customer classes and, in the case of the irrigation customers (Schedules 24 and 25), proposed a higher "out of season" energy rate. Following a discussion of the proposed increase to the customer charges, this section of the Order addresses Idaho Power's proposed rate changes for each customer class. We turn first to the proposal to rename the fixed customer charge.

Idaho Power proposed to change the name of the fixed "customer charge" to "service charge" for Schedules 1, 7, 9, 19, 24 and 25. Tr. at 790. The Company believes that the new name would more accurately describe the fixed service-related expenses the charge is designed to recover. *Id.* The other parties did not generally oppose the name change. Consequently we authorize the Company to change the fixed customer charge to "service charge." Although most witnesses referred to it in testimony as "customer charge," we will refer to it as the "service charge" in this Order.

1. The Service Charge.

As already noted, Idaho Power proposed significant increases in the service charge each class of customers pays each month. For example, residential customers (Schedule 1) and small general service customers (Schedule 7) currently pay a monthly service charge of $2.51, and the Company proposed to increase it to $10 per month for both classes. Exhibit 43 at 2-3. The Company proposed to increase the service charge for large general service customers

(Schedule 9—Secondary) from $5.54 to $21 per month. Exhibit 43 at 4. Primary and transmission customers on Schedule 9, and many large power service customers (Schedule 19), would see a new monthly service charge of $500, a significant increase from either $5.54 or approximately $85 per month those customers currently are paying. Exhibit 43 at 5, 6, 8-10.

Idaho Power explained its reasoning for these significant increases. Company witness Brilz insisted that the proper expenses to be included in the service charge are "investment in meters, a portion of the investment associated with distribution facilities, the costs associated with meter reading and billing, and the costs associated with maintaining the availability of service regardless of whether such service is actually taken." Tr. at 754-55. In other words, the Company believes the service charge should include a component for "the collection of facilities and expenses (unrelated to energy) required to serve a customer from the grid." Tr. at 3171. With this objective in mind, Idaho Power witness Gale asserted the monthly fixed charge for residential customers "should actually be much higher than the current proposal, potentially in the $25 to $30 range." Tr. at 3169.

Every intervenor that addressed Idaho Power's proposal to significantly increase the fixed service charges opposed the proposal. The NW Energy Coalition testified that only costs for meters, line drops, meter reading, and billing are customer-specific and should be included in a service charge. Tr. at 2168. NW Energy Coalition witness Hirsh testified that costs related to distribution and other infrastructure "reflect area-wide conditions and cannot be attributed to an individual customer," and, thus do not belong in a monthly service charge. Tr. at 2170. In addition, the Energy Coalition expressed concern that customers become less motivated to reduce consumption and improve efficiency with a high fixed monthly charge, and that an increase in fixed charges disproportionately impacts low and fixed income customers. Tr. at 2177-79. The Community Action Partnership Association witness Ottens likewise testified that low income customers are hardest hit by a high service charge, stating: "Because it is a charge not directly correlated to the level of actual energy usage, low income customers cannot compensate by simply turning the lights off and the heat down." Tr. at 2100-01.

Staff witness Schunke testified that a service charge "should be based on the direct cost of meter reading and billing and should not include any fixed plant cost." Tr. at 1690. Mr. Schunke expressed concern that "a large customer charge would also be inconsistent with energy conservation goals," noting that "the [residential] customer with the lowest usage would see a

298% increase while the largest users would see only an 8% increase." Tr. at 1688-89; Exhibit 44 at 1. AARP also urged the Commission to reject "IPC's per customer allocation of a significant part of the costs of the distribution system." Tr. at 2344-45. According to AARP witness Power, "the appropriate definition of customer costs is those that could be avoided if the customer ceased to take service," and would only include "those meter reading and billing functions that actually vary with the number of customers." Tr. at 2371.

The Commission finds that a monthly service charge should recover costs that are directly attributed to the customer paying the charge. Typically, those charges are related to meter reading and customer billing. For residential customers, the cost of service study indicates meter reading and customer billing costs are approximately $4.20 per month. Tr. at 1690. The Commission finds, however, that increasing the residential service charge to this level is not appropriate. We agree with the concerns expressed by the witnesses about the affects of a relatively high monthly service charge. In particular, fixed monthly charges dampen the incentive for customers to conserve energy.

The Commission finds that the appropriate service charge for residential customers is $3.30 per month. This is an increase of 31.47%. We find a service charge of that amount provides a reasonable balance between recovering specific customer service costs in a fixed fee while preserving the ability to provide price signals for conservation purposes. For the same reasons, the Commission approves increases in the service charges paid by most of the other customer classes, but establishes a charge lower than what Idaho Power proposed to strike a reasonable balance between the competing interests involved in establishing a fixed, monthly service charge and to reflect the lower overall revenue requirement approved by this Order. By increasing the service charges, the Commission also recognizes that Idaho Power will face reduced risk due to greater cost recovery through higher fixed charges and the increased cash flow that will result. The amount of the service charges for the other customer classes will be discussed as part of each class' rate design and are summarized as follows:

Rate Schedules	Current Service Charge	Ordered Service Charge
Residential (1)	$2.51	$3.30
Small General Service (7)	$2.51	$3.30
Large General Service (9 secondary)	$5.54	$5.60
Large General Service (9 primary and transmission)	$85.58	$125.00
Industrial (19 secondary)	$5.54	$5.60
Industrial (19 primary and transmission)	$85.71	$125.00
Irrigation (24 and 25) • in-season • out-of-season	$10.07 $2.50	$12.00 $3.00

2. Residential Customers (Schedule 1).

Idaho Power proposed implementing higher summer energy rates for residential and small general service customers (Schedules 1 and 7). The proposed summer months are June, July and August.[3] The Company explained it is the summer peak usage that requires it to obtain energy from higher cost sources, such as Idaho Power's Danskin plant or by purchasing power from the wholesale market. The higher summer rates "are intended to signal customers that consumption during the summer months is more costly." Tr. at 783-84. The Company did not propose to include a "block" of energy during the summer at a lower, non-summer rate, and instead proposed that all energy consumption during the three summer months be charged a rate 25% higher than the non-summer rate.

Staff witness Schunke agreed with the objectives of a higher residential summer rate, advocating a "peak period energy rate [that] would be about 20% higher than the base rate to reflect the higher power supply cost in that period." Tr. at 1692. Staff proposed, however, that the summer rate apply only to energy used in excess of 800 kWh per month during the three summer months. AARP also recommended a lower rate for a block of energy, suggesting a price

[3] The Company also proposes to implement rate differential designs for large general service, large power and irrigation customers (Schedules 9, 19, 24 and 25). Rate differentials for these customers are discussed in the appropriate sections below.

differential at 400 kWh per month. Tr. at 2364. AARP proposed a rate 25% higher for usage above the 400 kWh block, and also proposed leaving the two rates in effect year-round rather than just during the summer. Tr. at 2364-66. According to AARP, a higher rate in effect only during the summer does not address the winter peak that also occurs on Idaho Power's system, and AARP testified a year-round tiered rate would help convey to customers the higher marginal energy cost that occurs in both the summer and winter peaks. Tr. at 2364. AARP witness Power testified that a modest block of energy at lower rates "will provide some rate relief for smaller households and those who cannot afford larger homes and more electric using appliances." Tr. at 2366. The NW Energy Coalition witness Hirsh also expressed support for a block rate design "as an alternative to a high customer charge and as a way to alert customers to the high cost of power during peak load hours." Tr. at 2198-99.

Company witness Brilz opposed the proposals for a block rate structure in rebuttal testimony, stating that "the proposed blocked rates have no cost basis, penalize customers who utilize electric energy for space heating, and provide an artificially low price signal to customers who use less than the second-block threshold amount." Tr. at 2965. Ms. Brilz explained, regarding its cost basis argument, that a block rate structure does not address the variables that determine the costs of energy, "including the time of day and time of year during which it is produced or purchased, the balance between supply and demand, and the availability of transmission capacity." Tr. at 2966. Regarding electric space heat, Brilz argued that block rates "simply cause customers with electric space heat, many of whom do not have an alternative form of space heating available, to pay higher bills while other customers with other forms of space heat receive an artificially low price signal." Tr. at 2966-68. Regarding price signal, the Company argued a block rate structure "implies that the energy consumed by high-use customers is more valuable than energy consumed by low-use customers and, therefore, provides more emphasis on energy conservation by high-use customers than by low-use customers." Tr. at 2968

The Commission finds that a block of energy at a lower rate during the summer months is reasonable, fair and appropriate, and provides proper price signals during the period that the Company's energy costs are highest. We are not persuaded by Idaho Power's arguments against a block rate design, and note that variations on its arguments can be applied to the Company's proposal for a higher summer rate applied to all energy consumption. For example, a higher summer rate does not take into account the many variables that determine the costs of energy, but simply penalizes all customers that use energy during the summer, including customers that do not use electricity for air conditioning. We also believe, contrary to Idaho Power's argument, that it is proper to place emphasis on energy conservation by high-use residential customers because those customers are more likely to have a greater amount of discretionary use that can be curtailed. In fact, the Commission's rate design assists electric space heating customers because the higher rate applies only in the summer. By collecting a greater portion of the revenue requirement in the summer, winter energy rates are lower than they would otherwise need to be.

For residential customers, the Commission finds that a higher summer rate is appropriate for the summer peak months of June, July and August, except a 300 kWh block of energy should be available at a lower, non-summer rate. The summer rate should be high enough to send a price signal to customers that power used then is more costly. We find that a 12.56% differential is reasonable. Providing the first 300 kWh of summer usage at the non-summer rate allows some basic electric usage, such as for lighting and home appliances, that is not subject to the summer differential.

Based on the Commission approved revenue requirement and revenue allocation to the residential customers, the Commission finds a rate of $0.056940 per kWh is appropriate for summer usage above 300 kWh. A rate of $0.050585 per kWh is appropriate for the first 300 kWh of energy during the summer months and for all non-summer energy usage by residential customers.

3. Small General Service Customers (Schedule 7).

As with the residential customers, Idaho Power proposed to increase the service charge for small general service customers from $2.51 to $10 per month. For the same reasons discussed above, the Commission finds that a service charge of $3.30 per month is reasonable and appropriate for Schedule 7 customers.

The Company also proposed a higher summer rate for Schedule 7 customers, with no separate rate for a block amount of energy. Staff rate recommendations for Schedule 7 customers were similar to those for residential customers. Staff witness Schunke proposed summer rates that would include a lower rate for the first 600 kWh of energy consumed, and a higher rate for energy above the block amount. The lower block rate would also be in effect during the nine, non-summer months. Tr. at 1699-1701. Staff recommended the summer peak period rate should be approximately 17% higher than the lower non-summer rate.

Again for the same reasons we discussed in the above section on residential rates, the Commission finds that a summer block rate is appropriate for Schedule 7 customers. The Commission finds that a block rate design is appropriate for the summer peak months of June, July and August, and that the appropriate block for the lower rate is 300 kWh. Based on the Commission approved revenue requirement and revenue allocation to the Schedule 7 customers, the Commission finds a rate of $0.068538 per kWh for summer usage above 300 kWh is just, fair and reasonable. A rate of $0.060842 per kWh is appropriate for the first 300 kWh of energy used during June, July and August, and for all energy usage during the non-summer months. The differential between the summer second block and the non-summer energy rate is approximately 12.66%, or slightly higher than the 12.56% differential established for residential customers. While we recognize that variability in usage characteristics for this class may be significantly greater than those of the residential class, we believe that a summer first block of 300 kWh provides a reasonable average base level of consumption.

Idaho Power also proposed to change the way that customers' usage is evaluated to determine whether they qualify for Schedule 7 rates. Currently, a customer's usage is evaluated once each year, after which the customer is switched to a different schedule for the next year if the usage falls within a different schedule. The Company proposed to eliminate the annual review and instead review customer usage each month, making transfers to the appropriate schedule timelier. No one objected to this proposed change to Schedule 7, and the Commission finds it to be fair and reasonable.

4. Large General Service Customers (Schedule 9).

Large general service customers receive energy at levels classified as primary, secondary or transmission, and there are significant differences in some of the rate elements for the different customers. All Schedule 9 customers pay a service charge, an energy charge, a demand charge, a basic charge, and transmission level customers may also pay a facilities charge. The demand charge is assessed on peak demand each month and the basic charge is assessed on the average of the two highest peak demands for the current 12-month period. Tr. at 802. Idaho Power proposed increases in Schedule 9 service charges, basic charges, demand charges and energy charges, and in addition would implement summer rates for demand and energy charges.

Currently the service charge for Schedule 9 secondary service customers is $5.54 per month and is $85.58 per month for primary and transmission customers. Idaho Power proposed significant increases to the service charges—secondary service customers would pay $21 per month, and primary and transmission service customers would pay $500 per month. We do not believe changes in customer charges for secondary service Schedule 9 are warranted at the same level as those established for residential and general service schedules. These schedules already have service charges that more than recover the cost associated with fixed customer service costs and therefore should remain relatively unchanged at $5.60 per month. The Commission does find that Schedule 9 primary and transmission service charges should be increased to $125 per month to better reflect the higher fixed customer service costs associated with providing service under these schedules.

Idaho Power also proposed increases in the other Schedule 9 rates to recover its projected revenue requirement. Based on its much lower revenue requirement for the Company, Staff recommended a slight decrease in demand and energy charges for secondary service customers, but increases of approximately 13% in demand and energy charges for primary customers and transmission customers. Tr. at 1704-05. Kroger witness Higgins pointed out Staff's recommendation alters the price differential that currently exists in the Schedule 9 rates. Under current rates, primary service is 9 to 13 percent less expensive than secondary service, "but under Staff's proposal, this differential is virtually eliminated." Tr. at 2071. Kroger testified that primary service is cheaper to provide, and recommended that the existing price differential between the Schedule 9 types of service be retained. Tr. at 2079.

The Commission approves increases in the Schedule 9 demand and energy charges. Because the revenue requirement we approve is significantly lower than that proposed by the Company, the rates we find fair and reasonable are lower than the Company requested. We also agree with Kroger that a price differential should be maintained between the types of service in Schedule 9. We recognize that in some cases a customer may pay more taking primary service than secondary. Although this result seems counter-intuitive, it occurs because of the customer's particular configuration and usage. The basic charges the Commission finds to be fair, just and reasonable are $.37 per kW for secondary customers, $.85 per kW for primary customers, and

$.43 per kW for transmission customers. The demand charges the Commission approves for Schedule 9 are as follows:

> Secondary customers: summer $3.00 per kW; non-summer $2.73 per kW
>
> Primary customers: summer $3.16 per kW; non-summer $2.82 per kW
>
> Transmission customers: summer $3.06 per kW; non-summer $2.73 per kW

The energy charges the Commission approves for Schedule 9 are as follows:

> Secondary customers: summer $0.028903 per kWh; non-summer$0.025784 per kWh
>
> Primary customers: summer $0.025325 per kWh; non-summer $0.022700 per kWh
>
> Transmission customers: summer $0.024761 per kWh; non-summer $0.022291 per kWh

The Commission finds the rates set forth above to be just, fair and reasonable for Idaho Power's large general service customers. As we explained in our discussion of Schedule 7, Idaho Power also proposed new eligibility criteria for Schedule 9. The Commission approves the same change in the Schedule 9 tariffs.

Kroger recommended, noting Idaho Power's proposal to implement mandatory time-of-use (TOU) rates for Schedule 19, that the Commission also approve TOU rates for Schedule 9 "so that these customers could better respond to price signals, as well as pay rates that are more closely aligned with the costs they cause." Tr. at 2057-58. Kroger proposed the Schedule 9 TOU rates, however, should be voluntary, leaving it to individual customers to choose TOU rates. Tr. at 2061. In rebuttal testimony, Company witness Brilz testified that voluntary TOU rates are attractive only to customers that will benefit by lower rates, so that "the result is a reduction in revenue for the Company without any corresponding benefit." Tr. at 2979. Idaho Power also noted that only primary and transmission level customers currently have the metering in place to facilitate TOU pricing. The Company recommended that the TOU rates for Schedule 19 be implemented and evaluated prior to implementing TOU rates for Schedule 9 customers. Tr. at 2983.

The Commission finds the rebuttal arguments by Idaho Power to be persuasive and will not require TOU rates for Schedule 9 customers. However, we anticipate that after the

Company has gained experience with its Schedule 19 TOU rates, it will turn its attention to designing and proposing a TOU rate structure for Schedule 9.

5. Large Power Service Customers (Schedule 19).

The current rate structure for large power service customers is similar to the rate design of the large general service customers, and some of the rate changes Idaho Power proposed for Schedule 19 are the same as it proposed for Schedule 9. For example, large power customers currently pay service charges similar to service charges for Schedule 9 customers, and the Company proposed to increase all Schedule 19 service charges to $500 per month. The Commission approves the same service charges for Schedule 19 as it did for Schedule 9: secondary service customers will pay a $5.60 service charge, primary and transmission customers will pay a $125 per month service charge.

The most significant difference in the Company's proposals for Schedule 9 and Schedule 19 is to implement mandatory time-of-use (TOU) rates for Schedule 19 customers. The Company-proposed rates would include on-peak, mid-peak and off-peak energy prices to be in effect during June, July and August. During the other nine months, mid-peak and off-peak energy rates would be in effect. Staff witness Schunke testified that TOU rates are appropriate for Schedule 19 customers "who are sophisticated enough to understand them and where the metering equipment already exists." Tr. at 1706-07. Staff believes TOU rates send at least two important price signals: "The higher price during the periods when costs are higher encourages customers to reduce consumption and allows rates to be lower when the cost of power is lower, thus encouraging use during these off-peak periods. By shifting load, peaking facilities and peak power purchases can be reduced and existing base load facilities can be better utilized." Tr. at 1681.

DOE also supported implementation of mandatory TOU rates for Schedule 19, but expressed concern that some of the large commercial and industrial customers that take service under Schedule 19 are not prepared to operate cost-effectively under the new TOU rates. Tr. at 2247. DOE witness Goins recommended the TOU rates be implemented, but that the Commission "require IPC to prepare and file semiannual reports for the first year in which the rate is in effect concerning the implementation of the new TOU rate." Tr. at 2248. DOE's recommendation generated testimony from others about a phasing-in of the TOU rates.

The Industrial Customers opposed mandatory TOU rates for Schedule 19 customers. Noting the complexity of TOU rates, the Industrial Customers witness Teinert testified that Idaho Power "is proposing the implementation of the mandatory time-of-use rate without carefully analyzing the impact of the proposed Schedule 19 rate on either the Company or the Schedule 19 customers." Tr. at 1374. Mr. Teinert also testified that "Schedule 19 customers have not caused the Company to incur the costs associated with the need for summer peaking resources," one of the primary issues TOU rates are intended to address. Tr. at 1376. The Industrial Customers compared the Schedule 19 and residential customer classes for seasonal changes in load growth and customer growth in each class to support its argument that the Schedule 19 customers have not caused Idaho Power to invest in additional peaking resources. Tr. at 1376-78. In rebuttal testimony, the Industrial Customers expressed in stronger terms, in light of support of TOU rates from Staff and DOE, its objection to mandatory TOU rates.

The Commission approves the Company's proposal for mandatory TOU rates for Schedule 19, but requires a phase-in period before they are implemented. For a period of six months, Idaho Power shall provide two bills to the Schedule 19 customers. The second bill will show the charges that would be incurred under the TOU rates. After six months, Idaho Power can fully implement the TOU rates and bill customers according to the new rates. To accommodate the phase-in period, the Commission approves new rates for Schedule 19 for use during the first six months, and also approves TOU rates for implementation after six months. The new Schedule 19 rates approved by the Commission are set forth in Appendix 4, pages 7 through 12. The Commission finds these rates to be fair, just and reasonable.

Because this case represents the first time mandatory TOU rates have been established by the Commission, we find that summer peak and off-peak energy differentials should be established at conservative levels for the three Schedule 19 service classifications. The secondary differential is set at approximately 13%, the primary differential at approximately 19% and the transmission schedule at approximately 19%. Given the established phase-in period and the Company's expressed intent to file another general rate case within the next three years, we find the established differentials to be a reasonable first step toward implementing and evaluating mandatory TOU. As we explained in our discussion of Schedules 7 and 9, Idaho Power proposed new eligibility criteria for Schedule 19. The Commission approves the same change in the Schedule 19 tariffs.

The Industrial Customers witness Teinert objected to Idaho Power's current line extension provisions in Schedule 19 tariffs, and also to the monthly conservation charge paid by Schedule 19 customers because "currently Idaho Power does not administer any conservation or DSM [demand side management] programs specifically for the Schedule 19 customer class." Tr. at 1386. The Industrial Customers additionally objected to the Company's proposal to increase the minimum power factor in Schedule 19 from 85% to 90%.

The Company is not proposing any changes to the line extension provisions for Schedule 19 customers. Tr. at 884, 2991. The Commission approved those terms in January 1993. Tr. at 2991. The Commission is not convinced by the record in this case that the Schedule 19 tariff provisions on line extensions need to be revised. That said, we believe a proceeding to modify Idaho Power line extension schedules may be an appropriate offshoot of the cost of service investigation previously addressed in this Order. To the extent that investigation results in recommended changes to new customer contributions or allowances, a line extension proceeding will be a valid method of addressing those recommendations.

Regarding the Company's proposal to adjust the power factor minimum for Schedule 19 customers, the Industrial Customers simply asserted Idaho Power "does not offer evidence or testimony that its delivery system is capacity constrained due to power factor. Therefore, the increase in the minimum is not warranted." Tr. at 1386. In rebuttal testimony, Company witness Brilz testified its 2002 Integrated Resource Plan "identified multiple delivery system capacity constraints," and that its "distribution system is typically voltage and capacity constrained." Tr. at 2993. Brilz argued it "must install capacitors to correct for loads with less than unity power factors" in order to maintain system capacity. Tr. at 2993. The Commission approves the Company's proposal to increase the minimum power factor from 85% to 90% for Schedule 19 customers. The change will properly align the cost burden of customers whose reactive loads are placing increased costs on the Company.

Finally, regarding the Schedule 19 tariff provisions addressing conservation programs, Industrial Customers witness Teinert noted that each customer pays a monthly charge through the Company's Energy Efficiency Rider, Schedule 91, but that "currently Idaho Power does not administer any Conservation or DSM program specifically for the Schedule 19 customer class." Tr. at 1386. The Industrial Customers recommended, "each industrial and special contract customer should be allowed to use the funds it contributes to Idaho Power's energy efficiency rider for projects at their own industrial sites." Tr. at 1387. In rebuttal testimony, Idaho Power testified that its Industrial Efficiency Program began in October 2003, and that it is targeted at customers with 500 kW or more of load. Tr. at 2994. According to Company witness Brilz, "two proposals have been approved for implementation and an additional three proposals are undergoing the approval process." Tr. at 2994. Staff recommended the Commission make no change to the Energy Efficiency Rider. Tr. at 1716.

The Commission is not convinced the record in this case establishes that changes are required for the Energy Efficiency Rider, Schedule 91. The Commission would like the Company to develop and present a conservation program targeted specifically to Schedule 19 customers. The new time of use (TOU) rates we approve for the Schedule 19 customers are intended to assist them in identifying conservation measures for their facilities and operations. We note that the Industrial Efficiency Program implemented in October 2003 is targeted to customers whose load is at least 500 kW, while customers are required to have at least 1,000 kW of demand to qualify for Schedule 19 rates. There was no indication in the record that any of the five industrial efficiency proposals already approved or under review by Idaho Power were for Schedule 19 customers. Given the new, mandatory TOU rates for Schedule 19 customers, the Commission would like to see a DSM program that allows Schedule 19 customers to determine appropriate energy conservation improvements to their own facilities and receive matching funds from their contributions to Energy Efficiency Rider program to install the improvements. Idaho Power should work with the Schedule 19 industrial customers to develop a proposal to submit to the Commission.

6. Irrigation Customers (Schedule 24 and Schedule 25).

Idaho Power did not propose significant rate design changes for irrigation customers. The controversial issue was the amount of the rate increase the irrigation class should receive. The Commission previously discussed the cost of service results, where the Company proposed a Schedule 24 rate increase of 25% based on its recommended revenue requirement, and Staff proposed a 15% rate increase based on a much lower revenue requirement. Other parties recommended annual rate increases for the irrigation class to bring its rates in line with the cost of service study results.

The Company proposed to increase the irrigation class service charge, which currently is $10.07 per month during the "in-season" period (May through September) and is

$2.50 per month for the "out-season" period. Idaho Power proposed to increase only the in-season service charge, to $25 per month for secondary service customers and $500 per month for transmission level customers, although currently the Company has no transmission level irrigation customers. The Company also would increase the in-season demand charge from $3.58 per kW to $5.40 per kW, and the energy rate from $0.028416 (in-season) to $0.032634 per kWh.

To implement its recommended revenue requirement, Staff proposed to increase the in-season Schedule 24 service charge from $10.07 to $12, and the out-season service charge and the minimum charge from $2.50 to $3 per month. Tr. at 1710. Staff proposed an in-season demand charge of $4 per kW and an out-season demand charge of $.80 per kW. Finally, Staff proposed to change the existing energy rates to remove the in-season and out-season differential so that both rates are equal at $0.032830 per kWh. Tr. at 1710.

The Commission finds that an overall rate increase of 13.95% for the irrigation customers is just, fair and reasonable. We recognize that this rate increase is significant. However, it is unavoidable. Even if the precise results of the cost of service methodology are discounted, the large disparity between those results and existing irrigation base rates shows that in a relative sense, the irrigation class does not pay its own way, and other customer classes makeup the difference. Even with this large increase, the irrigation class remains behind relatively in sharing the cost burden as demonstrated by the currently used cost of service methodology. We find, to recover the assigned revenue requirement, the appropriate in-season service charge for Schedule 24 is $12, and the demand charge is $4 per kW. The Commission also finds a year-round energy rate of $0.032440 per kWh and an out of season demand charge of $0.80 per kW to be just, fair and reasonable for Schedule 24 customers.

Idaho Power also proposed to remove non-agricultural irrigation customers from Schedule 24. The Company stated that there are approximately 768 customers that use irrigation for city parks, school grounds, cemeteries, common areas in subdivisions, and golf courses. Tr. at 842. Idaho Power proposed to restrict Schedule 24 to agricultural use, and would move the other customers to a higher priced general service schedule. The Company did not provide evidence of the revenue impact of restricting Schedule 24 to agricultural use, nor did it provide any justification for creating a distinction between different types of irrigation customers. The

Commission denies the Company this proposed restriction for Schedule 24 customers without further evidence that distinguishes these uses from agriculture.

Schedule 25 is a pilot irrigation program that implemented time-of-use rates in October 2002. The Company plans to provide service under Schedule 25 through 2007, but is not allowing new customers to sign on for Schedule 25 service. Idaho Power proposed increases in the Schedule 25 rates and charges similar to those for Schedule 24. Tr. at 835-36, 1714-15. We find, to recover the assigned revenue requirement, the appropriate in-season service charge for Schedule 25 is $12, and the demand charge is $4 per kW. The Commission also finds energy rates of $0.058854 per kWh (on-peak), $0.016815 per kWh (off-peak), and $0.033631 kWh (mid-peak and out season) to be just, fair and reasonable for Schedule 25 customers. These TOU rate differentials, while larger than those established for Schedule 19, are for a voluntary summer only program and therefore are deemed appropriate in this case.

7. Other Rate Design Issues (Schedules 15, 40, 41, 42 and Schedules 26, 29, 30).

Consistent with its proposed revenue requirement and cost of service study results, the Company proposed increases in rates for Dusk to Dawn Lighting (Schedule 15), Unmetered General Service (Schedule 40), Street Lighting (Schedule 41) and Traffic Control (Schedule 42). Idaho Power also proposed changes to some of the terms of service in these schedules. For example, the Company would change Schedule 15 to allow light fixtures to be installed on a customer provided support acceptable to the Company rather than restricting attachment to a Company-owned pole. Based on its revenue requirement and cost of service results, Staff proposed modest increases or, in some cases, modest decreases in the rates for these schedules.

The parties did not address the Company's proposed changes in the terms of Schedules 15, 40, 41 and 42. The Commission approves the Company's proposed tariff changes, but not the Company's proposed rates. The rates for Schedules 15, 40, 41 and 42 that the Commission has determined are just, fair and reasonable, are based on its approved revenue requirement contained in Appendix 3. Rate components for these schedules are modified on an equal percentage based upon the percentage change in class revenue requirement.

The Company also proposed rate increases for its special contract customers Micron (Schedule 26), Simplot (Schedule 29) and DOE (Schedule 30), and Staff recommended modest increases or rate decreases for these customers. The rates for Schedules 26, 29 and 30 that the Commission has determined are just, fair and reasonable, are based on its approved revenue requirement contained in Appendix 3. Rate components for these special contracts are modified on an equal percentage based upon the percentage change in revenue requirement established for each customer.

ADJUSTMENTS TO THE PCA

The Power Cost Adjustment (PCA) is a rate adjustment mechanism that annually adjusts a portion of customer rates to allow Idaho Power to recover or refund 90 percent of above or below normal load adjusted power supply costs. Tr. at 1620. Base power supply costs are established in a general rate case and are included in the revenue requirement that determines the base rates for the customer classes. The various components of the PCA are also reviewed and updated in a rate case, and Idaho Power accordingly proposed revisions to PCA calculations. The Company's Exhibit 36 shows four PCA component calculations the Company proposes to update, identified as Normalized PCA Expenses, the Normalized Base PCA Rate, the Idaho Jurisdictional Percentage, and the Expense Adjustment Rate for Growth (EARG).

Only the Commission Staff addressed the Company's proposed updates to the PCA calculations, and agreed with Idaho Power's adjustments to the Normalized PCA Expenses, the Normalized Base PCA Rate, and the Idaho Jurisdictional Percentage. Tr. at 1622-23. Noting significant differences between the Company and Staff positions on the EARG, the Company suggested a separate proceeding to address adjustments to the EARG. Staff made a motion at the hearing for the EARG to be considered in a proceeding outside this rate case. The Company as well as DOE supported this motion, and the Commission granted the motion. Tr. at 349. Accordingly, the Commission approves Idaho Power's proposed adjustments to the Normalized PCA Expenses, the Normalized Base PCA Rate, and the Idaho Jurisdictional Percentage components of the PCA.

Based upon the evidence in the record, we find Idaho Power's adjustments to the Normalized PCA Expenses, the Normalized Base PCA Rate, and the Idaho Jurisdictional Percentage to be just and reasonable. At the request of Staff, Idaho Power and DOE, the Commission will consider adjustments to the EARG in a separate proceeding as discussed further in the "New Cases and Other Issues" section below.

INTERVENOR FUNDING

The Commission received timely requests for intervenor funding from the Idaho Irrigation Pumpers Association, Inc. ($75,554.40), Community Action Partnership Association of Idaho ($21,293.52), and NW Energy Coalition ($11,512.30). *Idaho Code* § 61-617A authorizes an intervenor cost award not to exceed a total of $40,000 for all intervening parties combined. Individual awards must be based on findings that the intervenor's participation materially contributed to the Commission's decision, the costs of intervention are reasonable and would be a significant financial hardship for the intervenor if no award is given, the recommendations made by the intervenor differed materially from Staff's evidence, and the intervenor's participation addressed issues of concern to the general body of users or consumers.

All three of the intervenors requesting funding materially contributed to the Commission's decisions through their participation. Although the Commission did not adopt all the proposals advocated by the intervenors, the advocacy of each intervenor influenced the ultimate decisions that have been made. Each of the intervenors offered evidence that differed materially from that offered by Staff. Each intervenor addressed issues of concern to the general body of users or consumers, although this standard was met more completely by Community Action and NW Energy, who participated in the case to represent public consumers in general rather than a particular group of business customers.

The intervenor funding statute requires the Commission to consider reasonableness in the costs of intervention and the relative hardship for each intervenor. Each of the three intervenors fully participated in the case by presenting prefiled testimony, attending the hearings, and cross-examining witnesses. Community Action and NW Energy are public interest entities with modest financial resources and would probably not be able to participate without intervenor funding. They brought a perspective to the hearing that has historically been lacking or under-represented. We appreciate their frugal approach to their funding requests.

Based on the record and the intervenor funding requests, we find that the policy stated in *Idaho Code* § 61-617A to encourage participation in Commission proceedings "so that all affected customers receive full and fair representation" is furthered by awarding intervenor funding to the Irrigators and Community Action the amount of $15,000 each, and NW Energy the amount of $10,000. Community Action and NW Energy intervenor funding awards of $15,000 and $10,000, respectively, are to be recovered from Schedule 1 customers, and the Irrigators' award of $15,000 shall be recovered from Schedule 24 customers. We believe it is reasonable to collect these amounts from the appropriate classes in the 2005-2006 PCA for the reasons set forth above in our discussion of test year intervenor funding. We also note that it is extremely difficult to allocate a fixed monetary amount over reasonable requests that far exceed that allowed by statute. However, we believe this allocation best satisfies the considerations set forth in *Idaho Code* § 61-617A.

NEW CASES AND OTHER ISSUES

Several issues arose in the testimony that the Commission has determined should be addressed in separate proceedings, although each may be handled in a workshop setting that does not require a formal hearing. As previously mentioned, the Commission at the hearing granted Staff's motion for a separate proceeding to address Expense Adjustment Rate for Growth component of the PCA formula. Idaho Power and Staff are directed to determine a schedule for one or more workshops and initiate a docket to address this piece of the PCA.

A proposal for a second workshop proceeding was sponsored by NW Energy Coalition, which argued that financial disincentives hinder Idaho Power's investments in cost-effective energy efficiency and clean distributed generation. NW Energy Post Hearing Brief at 1. NW Energy filed with its brief an agreement signed by representatives of NW Energy, Idaho Power, Staff and Industrial Customers committing them, should the Commission determine that removing the disincentives is in the public interest, to "work together to investigate specific mechanisms for achieving this objective, to identify areas of consensus, and to clarify alternatives where consensus is not possible." NW Energy Joint Proposal at 1. The Commission has determined that a proceeding to assess financial disincentives inherent in Company-sponsored conservation programs is appropriate and should proceed by informal workshops. The Commission specifically directs the parties to address possible revenue adjustment when annual energy consumption is both above and below normal. The parties should also consider how much adjustment is necessary to remove DSM investment disincentives and whether (and to what extent) performance-based incentives such as revenue sharing could or should be incorporated into the resolution of this issue. The Commission is interested in proposals that could provide Idaho Power the opportunity to share and retain benefits gained from efficiencies, especially where efficiencies are derived from innovation and the use of new technologies. For example, a proposal might include a way to average expense reductions that result in efficiencies on the system that benefit the Company and its shareholders while maintaining or improving service quality standards. The parties may also consider including service quality standards or benchmarks as a component of an incentive mechanism. In short, the Commission believes opportunities exist for improvements in operating efficiency that would benefit the Company shareholders and its customers, and we encourage the parties to creatively consider the options for a performance based mechanism to present to the Commission. The parties to the agreement are directed to propose a workshop schedule and initiate a proceeding.

As previously stated, the Commission has also determined to initiate a proceeding to consider and evaluate cost of service issues raised in this case. Witnesses for the Industrial Customers, Micron, DOE and the Irrigators all identified problems with the cost of service study components. These issues should be further investigated before the next Idaho Power general rate case. The Commission also received testimony from irrigation customers and other ratepayers who were concerned with how investments necessitated by customer growth should be paid. Tr. at 65-7, 2036. These witnesses suggested that a revised line extension policy could appropriately align cost recovery with the customers who create the need for system improvements. Consequently, the Commission has specifically directed the parties to address load growth issues in the cost of service proceeding to determine if line extension modifications are necessary. Staff is directed to determine a workshop schedule and initiate a proceeding for that purpose.

Finally, the Commission's Consumer Division Staff presented in testimony specific recommendations for Idaho Power to improve customer service issues. To its credit, the Company responded in a positive way to Staff's recommendations, agreeing to implement the recommendations or, in one case, by making suggestions that improved the recommendations. These issues do not require a separate proceeding, but Staff should review the Company's implementation of the changes it agreed to and report to the Commission should any significant issues arise in the implementation process.

ULTIMATE FINDINGS OF FACT

Idaho Power Company is an electrical corporation subject to the Commission's regulation under the Idaho Public Utilities Law. The rates of all its tariff customers in the State of Idaho and of its contract customers are subject to this Commission's regulation under the Public Utilities Law.

The Company's present rates do not provide it with an opportunity to earn a fair and reasonable return on its investment. Allowing the Company to increase its rates and charges by

$25,329,438 will provide it with the opportunity to earn a fair and reasonable return. The average 2003 test year is the appropriate test year period for use in this proceeding.

The adjusted test year net operating income for Idaho of $103,918,528 is just and reasonable for setting rates. The test year adjusted rate base for Idaho of $1,519,924,799 is just and reasonable for setting rates. Idaho Power's actual capital structure at December 31, 2003 is the appropriate one for this case and an overall rate of return of 7.852%, to be applied to all rate base, is a fair and reasonable rate of return for the Company.

The revenue allocation shown in Appendix 3 is a just, reasonable and non-discriminatory allocation of the Company's revenue requirement among the various customer classes. It is also fair, just and reasonable to design the customer class rates according to the directives contained in the text of this Order.

The awards of intervenor funding in the amounts of $10,000 to NW Energy Coalition, $15,000 to Idaho Irrigation Pumpers Association, Inc., and $15,000 to Community Action Partnership Association of Idaho are reasonable.

CONCLUSIONS OF LAW

This Commission has jurisdiction and authority to authorize and require Idaho Power Company to re-allocate its revenues among the customer classes, to change its rate components within the customer classes, to address the other issues and to award intervenor funding in the manner set forth in the text of this Order.

O R D E R

IT IS HEREBY ORDERED that Idaho Power Company file tariffs in conformance with this Order to be effective on June 1, 2004, for service rendered on and after that date.

IT IS FURTHER ORDERED that Idaho Power Company comply with all other directives of the text of this Order.

IT IS FURTHER ORDERED that the Community Action Partnership Association of Idaho comply with the conditions and reporting requirements associated with the Low Income Weatherization Assistance funding authorized by this Order.

IT IS FURTHER ORDERED that the parties determine a workshop schedule and initiate separate proceedings to resolve issues regarding the Expense Adjustment Rate for Growth, financial disincentives in Company-sponsored conservation programs, and cost of service study components (including whether load growth is properly recovering its cost) as discussed in this Order.

IT IS FURTHER ORDERED that NW Energy Coalition is awarded intervenor funding in the amount of $10,000, the Idaho Irrigation Pumpers Association, Inc. is awarded intervenor funding in the amount of $15,000, and Community Action Partnership Association of Idaho is awarded intervenor funding in the amount of $15,000. Idaho Power is directed to pay these amounts within 28 days of the date 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 this Case No. IPC-E-03-13 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 this Case No. IPC-E-03-13. 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 25th day of May 2004.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Marsha H Smith

MARSHA H. SMITH, COMMISSIONER

Dennis S. Hansen

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell

Jean D. Jewell
Commission Secretary

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IPUC FINAL ORDER
JURISDICTIONAL SEPARATION STUDY - REVENUE REQUIREMENT
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2003

1		**TOTAL**	**IDAHO**
2	**DESCRIPTION**	**SYSTEM**	**IPUC**
3			
4	**RATE OF RETURN UNDER PRESENT RATES**		
5	TOTAL COMBINED RATE BASE	1,643,706,370	1,519,924,799
6			
7	**SALES REVENUES**	576,039,178	543,332,605
8	OTHER OPERATING REVENUES	42,464,061	35,419,775
9	TOTAL OPERATING REVENUES	618,503,239	578,752,380
10			
11	**OPERATING EXPENSES**		
12	OPERATION & MAINTENANCE EXPENSES	367,262,862	343,856,114
13	DEPRECIATION EXPENSE	93,106,208	86,136,616
14	AMORTIZATION OF LIMITED TERM PLANT	9,825,386	9,090,099
15	TAXES OTHER THAN INCOME	20,910,436	18,979,024
16	PROVISION FOR DEFERRED INCOME TAXES	3,109,043	3,002,364
17	INVESTMENT TAX CREDIT ADJUSTMENT	(308,166)	(297,592)
18	FEDERAL INCOME TAXES	18,038,536	17,193,496
19	STATE INCOME TAXES	3,693,140	3,560,916
20	TOTAL OPERATING EXPENSES	515,637,445	481,521,037
21			
22	**OPERATING INCOME**	102,865,794	97,231,343
23	ADD: IERCO OPERATING INCOME	7,106,583	6,687,185
24	CONSOLIDATED OPERATING INCOME	109,972,377	103,918,528
25	RATE OF RETURN UNDER PRESENT RATES	6.69%	6.84%
26			
27	**DEVELOPMENT OF REVENUE REQUIREMENTS**		
28	RATE OF RETURN REQUIRED @ 10.25% ROE		7.852%
29			
30	RETURN AT CLAIMED RATE OF RETURN		119,344,495
31	EARNINGS DEFICIENCY		15,425,967
32			
33	NET-TO-GROSS TAX MULTIPLIER		1.642
34	REVENUE DEFICIENCY		25,329,438
35			
36	FIRM JURISDICTIONAL REVENUES		483,961,369
37	PERCENT INCREASE REQUIRED		5.23%
38			
39	SALES AND WHEELING REVENUES REQUIRED		509,290,807

APPENDIX 2
ORDER NO. 29505
CASE NO. IPC-E-03-13
PAGE 1 OF 2

IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY FOR IDAHO POWER COMPANY
TWELVE MONTHS ENDING DECEMBER 31, 2003

	SOURCES & NOTES	(A) TOTAL	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	0 GEN SRV TRANS (9-T)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	0 LG POWER TRANS (19-T)	(G) LG POWER PRIMARY (19-P)	0 LG POWER SECONDARY (19-S)	0 IRRIGATION TRANS (24-T)	(H) IRRIGATION SECONDARY (24-S)
****** REVENUE REQUIREMENT SUMMARY ******													
TOTAL RATE BASE		1,519,924,799	629,710,986	45,803,960	0	35,832,890	288,900,655	1,289,454	0	171,276,819	0	0	272,107,742
REVENUES FROM RATES													
RETAIL		483,961,369	214,289,412	16,798,479	0	10,319,873	97,349,138	1,389,112	0	55,063,581	0	0	60,291,580
TOTAL SALES REVENUES		483,961,369	214,289,412	16,798,479	0	10,319,873	97,349,138	1,389,112	0	55,063,581	0	0	60,291,580
TOTAL OTHER OPERATING REVENUES		94,792,171	33,785,757	2,106,400	0	3,151,602	18,487,831	148,307	0	16,423,182	0	0	13,379,886
TOTAL REVENUES		578,753,540	248,075,169	18,904,879	0	13,471,475	115,836,969	1,537,419	0	71,486,763	0	0	73,671,466
OPERATING EXPENSES													
WITHOUT INC TAX		460,766,625	192,670,974	14,867,301	0	11,110,691	87,746,987	310,968	0	55,521,489	0	0	71,048,657
OPERATING INCOME													
BEFORE INCOME TAXES		117,986,915	55,404,195	4,037,577	0	2,360,784	28,089,983	1,226,451	0	15,965,274	0	0	2,622,809
TOTAL FEDERAL INCOME TAX		17,193,496	8,073,707	588,371	0	344,022	4,093,378	178,723	0	2,326,520	0	0	382,206
TOTAL STATE INCOME TAX		3,560,916	1,672,132	121,857	0	71,250	847,773	37,015	0	481,842	0	0	79,158
TOTAL OPERATING EXPENSES		481,521,037	202,416,813	15,577,529	0	11,525,963	92,688,137	526,706	0	58,329,850	0	0	71,510,021
TOTAL OPERATING INCOME		97,232,503	45,658,356	3,327,350	0	1,945,512	23,148,832	1,010,713	0	13,156,912	0	0	2,161,445
ADD: IERCO OPERATING INCOME	E10	6,687,185	2,285,680	147,118	0	186,572	1,479,874	2,675	0	1,057,244	0	0	968,973
CONSOLIDATED OPER INCOME		103,919,688	47,944,036	3,474,468	0	2,132,084	24,628,706	1,013,387	0	14,214,156	0	0	3,130,418
RATES OF RETURN		6.837	7.614	7.586	0.000	5.950	8.525	78.590	0.000	8.299	0.000	0.000	1.150
RATES OF RETURN - INDEX		1.000	1.114	1.109	0.000	0.870	1.247	11.495	0.000	1.214	0.000	0.000	0.168
AVERAGE MILLS/KWH		40.09	51.74	63.31	0.00	29.74	36.50	0.00	0.00	27.83	0.00	0.00	37.20
REVENUE REQUIREMENT CALCULATION													
RATE OF RETURN REQUIRED		7.852	7.852	7.852	7.852	7.852	7.852	7.852	7.852	7.852	7.852	7.852	7.852
REQUIRED REVENUE		509,288,902	216,753,841	16,998,900	0	11,438,919	94,156,717	(108,621)	0	53,806,629	0	0	90,234,241
REVENUE DEFICIENCY		25,327,533	2,464,429	200,421	0	1,119,046	(3,192,421)	(1,497,733)	0	(1,256,952)	0	0	29,942,661
PERCENT CHANGE REQUIRED		5.23%	1.15%	1.19%	0.00%	10.84%	-3.28%	-107.82%	0.00%	-2.28%	0.00%	0.00%	49.66%
RETURN AT CLAIMED ROR		119,344,495	49,444,907	3,596,527	0	2,813,599	22,684,479	101,248	0	13,448,656	0	0	21,365,900
EARNINGS DEFICIENCY		15,424,807	1,500,871	122,059	0	681,514	(1,944,227)	(912,139)	0	(765,501)	0	0	18,235,481
REVENUE REQUIREMENT FOR RATE DESIGN													
TOTAL IDAHO SALES REVENUES		483,961,369	214,289,412	16,798,479	0	10,319,873	97,349,138	1,389,112	0	55,063,581	0	0	60,291,580
DESIRED CHANGE IN REVENUE (%)		5.23	1.15	1.19	0.00	10.84	-3.28	-107.82	0.00	-2.28	0.00	0.00	49.66
SALES REVENUE DESIRED		509,288,902	216,753,841	16,998,900	0	11,438,919	94,156,717	(108,621)	0	53,806,629	0	0	90,234,241
RATE OF RETURN AT DESIRED REVENUE		7.852	7.852	7.852	0.000	7.852	7.852	7.852	0.000	7.852	0.000	0.000	7.852
DESIRED AVERAGE MILLS/KWH		42.18	52.34	64.07	0.00	32.96	35.30	0.00	0.00	27.19	0.00	0.00	55.67
ACTUAL RATE OF RETURN (SALES REVENUE ONI		0.16	1.89	2.67	0.00	-3.37	1.61	66.88	0.00	-1.91	0.00	0.00	-4.12
DESIRED RATE OF RETURN (SALES REVENUE ON		1.83	2.28	3.10	0.00	-0.24	0.51	-49.27	0.00	-2.64	0.00	0.00	6.88

IDAHO PUBLIC UTILITIES COMMISSION
CLASS COST OF SERVICE STUDY FOR IDAHO POWER COMPANY
TWELVE MONTHS ENDING DECEMBER 31, 2003

Row	*** REVENUE REQUIREMENT SUMMARY ***	SOURCES & NOTES	TOTAL	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INEL	(M) SC JR SIMPLOT	(N) SC MICRON
190	TOTAL RATE BASE		1,519,924,799	1,991,902	2,797,866	820,828	12,974,245	14,555,822	41,861,630
192	REVENUES FROM RATES		0						
193	RETAIL		483,961,369	907,691	1,809,265	284,147	4,622,413	4,632,571	16,204,107
195	TOTAL SALES REVENUES		483,961,369	907,691	1,809,265	284,147	4,622,413	4,632,571	16,204,107
197	TOTAL OTHER OPERATING REVENUES		94,792,171	119,751	284,327	63,465	1,233,339	1,665,526	3,942,798
199	TOTAL REVENUES		578,753,540	1,027,442	2,093,592	347,612	5,855,752	6,298,097	20,146,905
201	OPERATING EXPENSES		0						
202	WITHOUT INC TAX		460,766,625	633,965	1,477,963	271,827	4,713,117	4,629,718	15,762,966
203			0						
204	OPERATING INCOME		0						
205	BEFORE INCOME TAXES		117,986,915	393,477	615,629	75,785	1,142,634	1,668,378	4,383,939
207	TOTAL FEDERAL INCOME TAX		17,193,496	57,339	89,712	11,044	166,509	243,122	638,844
208	TOTAL STATE INCOME TAX		3,560,916	11,875	18,580	2,287	34,485	50,353	132,310
210	TOTAL OPERATING EXPENSES		481,521,037	703,179	1,586,255	285,158	4,914,112	4,923,193	16,534,120
212	TOTAL OPERATING INCOME		97,232,503	324,263	507,337	62,454	941,640	1,374,903	3,612,785
213			0						
214	ADD: IERCO OPERATING INCOME	E10	6,687,185	9,362	10,031	5,350	104,320	96,964	333,022
215	CONSOLIDATED OPER INCOME		103,919,688	333,625	517,368	67,803	1,045,960	1,471,867	3,945,807
217	RATES OF RETURN		6.837	16.749	18.492	8.260	8.062	10.112	9.426
218	RATES OF RETURN - INDEX		1.000	2.450	2.705	1.208	1.179	1.479	1.379
219	AVERAGE MILLS/KWH		40.086	56.54	0.00	30.28	22.76	24.81	25.44
221	***REVENUE REQUIREMENT CALCULATION***		0						
222	RATE OF RETURN REQUIRED		7.852	7.852	7.852	7.852	7.852	7.852	7.852
224	REQUIRED REVENUE		509,288,902	616,695	1,320,475	278,643	4,577,714	4,092,444	15,122,305
225	REVENUE DEFICIENCY		25,327,533	(290,996)	(488,790)	(5,504)	(44,699)	(540,127)	(1,081,802)
226	PERCENT CHANGE REQUIRED		5.23	-32.06%	-27.02%	-1.94%	-0.97%	-11.66%	-6.68%
227	RETURN AT CLAIMED ROR		119,344,495	156,404	219,688	64,451	1,018,738	1,142,923	3,286,975
228	EARNINGS DEFICIENCY		15,424,807	(177,221)	(297,680)	(3,352)	(27,222)	(328,944)	(658,832)
230	***REVENUE REQUIREMENT FOR RATE DESIGN***								
231	TOTAL IDAHO SALES REVENUES		483,961,369	907,691	1,809,265	284,147	4,622,413	4,632,571	16,204,107
233	DESIRED CHANGE IN REVENUE (%)		5.23	-32.06	-27.02	-1.94	-0.97	-11.66	-6.68
235	SALES REVENUE DESIRED		509,288,902	616,695	1,320,475	278,643	4,577,714	4,092,444	15,122,305
236	RATE OF RETURN AT DESIRED REVENUE		7.852	7.852	7.852	7.852	7.852	7.852	7.852
237	DESIRED AVERAGE MILLS/KWH		42.18	38.41	0.00	29.69	22.54	21.92	23.74
239	ACTUAL RATE OF RETURN (SALES REVENUE ONL'		0.16	10.27	7.97	-0.12	-2.25	-2.00	-0.79
240	DESIRED RATE OF RETURN (SALES REVENUE ONI		1.83	-4.34	-9.50	-0.79	-2.59	-5.71	-3.37

APPENDIX 2
ORDER NO. 29505
CASE NO. IPC-E-03-13
PAGE 2 OF 2

APPENDIX 3
ORDER NO. 29505
CASE NO. IPC-E-03-13

Idaho Power Company
Summary of Revenue Impact
IPC State of Idaho
Normalized 12-Months Ending December 31, 2003

Line No	Tariff Description	(1) Rate Sch. No.	(2) 2003 Avg. Number of Customers	(3) 2003 Sales Normalized (kWh)	(4) Current Base Revenue	(5) Approved Base Revenue	(6) Avg. Mills Per KWH	(7) Percent Change	(8) COS INDEX
	Uniform Tariff Rates:								
1	Residential Service	1	335,605	4,141,393,426	214,289,414	227,113,782	54.84	5.98%	105%
2	Small General Service	7	32,316	265,335,667	16,798,476	17,801,080	67.09	5.97%	105%
3	Large General Service	S9	17,299	2,667,376,237	97,349,138	99,278,739	37.22	1.98%	105%
	Large General Service	P9	116	347,050,749	10,319,874	11,393,164	32.83	10.40%	100%
4	Dusk to Dawn Lighting	15	-	5,872,586	1,389,106	887,957	151.20	(36.08)%	*
6	Large Power Service	19	105	1,978,824,237	55,063,573	56,393,250	28.50	2.41%	105%
7	Agricultural Irrigation Service	24	13,517	1,620,930,931	60,397,510	68,825,609	42.46	13.95%	76%
8	Unmetered General Service	40	1,224	16,054,942	907,689	821,534	51.17	(9.49)%	133%
9	Street Lighting	41	1,432	17,912,039	1,809,269	1,669,557	93.21	(7.72)%	126%
10	Traffic Control Lighting	42	58	9,384,218	284,145	292,036	31.12	2.78%	105%
11	*Total Uniform Tariffs*		401,672	11,070,135,032	458,608,194	484,476,708	43.76	5.64%	100%
	Special Contracts:								
12	Micron	26	1	636,967,670	16,204,104	15,802,806	24.81	(2.48)%	105%
13	J R Simplot	29	1	186,684,665	4,632,571	4,317,524	23.13	(6.80)%	105%
14	DOE	30	1	203,084,146	4,622,414	4,797,778	23.62	3.79%	105%
15	*Total Special Contracts*		3	1,026,736,481	25,459,089	24,918,108	24.27	(2.12)%	105%
16	***Total Idaho Retail Sales***		401,675	12,096,871,513	484,067,283	509,394,816	42.11	5.23%	100%

* *Anomaly in the Cost of service analysis results in a negative COS index*

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

Residential Service
Schedule 1

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge	4,018,999.3	$2.51	$10,087,688	3.30	$13,262,698	$3,175,010	31.47%
2	Mininum Serv Chg	26,959.1	$1.00	26,959	3.00	80,877	53,918	200.00%
	Summer < 300kwh	257,623,905	0.049303	12,701,631	0.050585	13,031,905	330,274	2.60%
3	Summer>300 kwh	674,448,811	0.049303	33,252,350	0.056940	38,403,115	5,150,765	15.49%
4	Non-Summer	3,209,320,710	0.049303	158,229,139	0.050585	162,343,488	4,114,349	2.60%
5	Total kWh	4,141,393,426		204,183,120		213,778,508	9,595,388	4.70%
	summer differential				0.006355			12.56%
6	Customer Adj.			(8,353)		(8,353)	0	0.00%
7	Total Billing			$214,289,414		$227,113,730	$12,824,316	5.98%

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003

Small General Service
Schedule 7

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) Revenue Difference	(7) Percent Change
1	Service Charge	385,824.8	$2.51	$968,420	$3.30	$1,273,222	$304,802	31.47%
2	Minimum Serv Chg	1,174.3	1.00	1,174	3.00	3,523	2,349	200.09%
3	Summer>300 kwh	49,234,131	0.059649	$2,936,767	0.068538	3,374,409	437,642	14.90%
4	Summer <300	19,241,210	0.059649	1,147,719	0.060842	1,170,674	22,955	2.00%
5	Non-Summer	196,860,326	0.059649	11,742,522	0.060842	11,977,376	234,854	2.00%
6	Total kWh	265,335,667		15,827,008		16,522,459	257,809	1.63%
	summer differential				0.00770			12.66%
7	Customer Adj.			1,874		1,874	0	0.00%
8	Total Billing			$16,798,476		$17,801,078	$1,002,602	5.97%

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31. 2003
Approved Base Rates

Large General Service
Schedule 9 Secondary Service

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) % chg
1	Service Charge	203,548.2	$5.54	$1,127,657	$5.60	$1,139,870	1.1%
2	Minimum Serv Chg	516	2.50	1,290	5.00	2,580	100%
	Basic Charge						
3	Summer	2,830,683	0.36	1,019,046	0.37	1,047,353	2.8%
4	Non-Summer	7,910,008	0.36	2,847,603	0.37	2,926,703	2.8%
5	Total Basic Charge	10,740,691		3,866,649		3,974,056	2.8%
	Demand Charge						
6	Summer	2,194,920	2.73	5,992,132	3.00	6,584,760	9.9%
7	Non-Summer	6,133,445	2.73	16,744,305	2.73	16,744,305	0.0%
8	Total Demand	8,328,365		22,736,437		23,329,065	2.6%
	Energy Charge						
9	Summer	702,980,435	0.026150	18,382,938	0.028903	20,318,244	10.5%
10	Non-Summer	1,964,395,802	0.026150	51,368,950	0.025784	50,649,981	-1.4%
11	Total Energy	2,667,376,237		69,751,888		70,968,225	1.7%
	summer differential				0.003119		12.1%
12	Customer Adj.			(134,783)		(134,783)	0.0%
13	Total Billing			$97,349,138		$99,279,013	1.98%

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

Large General Service
Schedule 9 Primary Service

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) % chg
1	Service Charge	1,345.4	$85.58	$115,139	$125.00	$168,175	46%
2	Minimum Serv Chg	0	2.50	0	10.00	0	
	Basic Charge						
3	Summer	249,833	0.77	192,371	$0.85	212,358	10%
4	Non-Summer	729,799	0.77	561,945	$0.85	620,329	10%
5	Total Basic Charge	979,632		754,316		832,687	10%
	Demand Charge						
6	Summer	200,448	2.65	531,187	$3.16	633,416	19%
7	Non-Summer	564,734	2.65	1,496,545	2.82	1,592,550	6%
8	Total Demand	765,182		2,027,732		2,225,966	10%
	Energy Charge						
9	Summer	95,942,657	0.021308	2,044,346	0.025325	2,429,748	19%
10	Non-Summer	246,023,482	0.021308	5,242,268	0.022700	5,584,733	7%
11	Total Energy	341,966,139		7,286,614		8,014,481	10%
	summer differential				0.002625		12%
12	Customer Adj.			(15,973)		(15,973)	0%
13	Total Billing			$10,167,828		$11,225,336	10.40%

State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

Large General Service
Schedule 9 Transmission

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	% chg
1	Service Charge	24.0	$85.58	$2,054	$125.00	$3,000	46%
2	Minimum Serv Chg	0	2.50	0	10.00	0	
	Basic Charge						
3	Summer	4,411	0.39	1,720	0.43	1,897	10%
4	Non-Summer	11,353	0.39	4,428	0.43	4,882	10%
5	Total Basic Charge	15,764		6,148		6,779	10%
	Demand Charge						
6	Summer	3,901	2.57	10,026	3.06	11,937	19%
7	Non-Summer	10,778	2.57	27,699	2.73	29,424	6%
8	Total Demand Charge	14,679		37,725		41,361	10%
	Energy Charge						
9	Summer	1,290,504	0.020833	26,885	0.024761	31,954	19%
10	Non-Summer	3,794,106	0.020833	79,043	0.022291	84,574	7%
11	Total Energy Charge	5,084,610		105,928		116,528	10%
	summer differential				0.002470		11%
12	Customer Adj.			191		191	0%
13	Total Billing			$152,046		$167,859	10.40%

Idaho Power Company
Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

Dusk to Dawn Customer Lighting
Schedule 15

Line No	Description	(1) Use	(2) Lamps	(3) Current Base Rate	(5) Current Base Revenue	(6) Approved Base Rate	(7) Approved Base Revenue
	Lamps						
1	100-Watt Sodium Vapor (A)	3,664,282	108,117	8.71	$941,699	5.58	$603,293
2	200-Watt Sodium Vapor (A)	526,020	7,746	14.13	109,451	9.05	70,101
3	200-Watt Sodium Vapor (D)	586,867	8,547	17.18	146,837	11.00	94,017
4	400-Watt Metal Halide (D)	90,523	664	28.64	19,017	18.34	12,178
5	400-Watt Sodium Vapor (A)	156,334	1,144	22.55	25,797	14.44	16,519
6	400-Watt Sodium Vapor (D)	651,710	4,762	25.63	122,050	16.42	78,192
7	1000-Watt Metal Halide(D)	196,853	581	52.28	30,375	33.49	19,458
8	Total Com./Ind.	5,872,589	131,561		1,395,226		893,758
9	Minimum Charges		147	1.00	147	3.00	441
10	Customer Adj.	(3)			(6,267)		(6,267)
11	Total Lamp Revenue	5,872,586			$1,389,106		$887,932

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

Large Power Service
Schedule 19 Secondary TOU

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) % chg
1	Service Charge	12.0	$5.54	$66	$5.60	$67	1.5%
	Basic Charge						
2	Summer	4,777	0.36	1,720	$0.37	1,767	2.7%
3	Non-Summer	13,918	0.36	5,010	$0.37	5,150	2.8%
4	Total Basic Charge	18,695		6,730		6,917	2.8%
	Demand Charge						
5	Summer	4,592	2.73	12,536	2.85	13,087	4.4%
6	On-Peak Summer	4,530	0.00	0	0.36	1,631	new
7	Non-Summer	12,400	2.73	33,852	2.64	32,736	-3.3%
8	Total Demand Charge			46,388		47,454	2.3%
	Energy Charge						
9	On-peak Summer	616,860	0.025576	15,777	0.030169	18,610	18.0%
10	Mid-peak Summer	1,063,953	0.025576	27,212	0.028664	30,497	12.1%
11	Off-peak Summer	693,552	0.025576	17,738	0.026716	18,529	4.5%
12	Total Summer Energy Charge	2,374,364		60,727		67,636	11.4%
13	Mid-peak Non-Summer	3,953,230	0.025576	101,108	0.025790	101,954	0.8%
14	Off-peak Non-Summer	2,592,937	0.025576	66,317	0.024626	63,854	-3.7%
15	Total Non-Summer energy charge	6,546,167		167,425		165,808	-1.0%
16	Total Energy Charge	8,920,531		228,152		233,444	2.3%
17	Customer Adj.			637		637	0.0%
18	Total Billing			$281,973		$288,519	2.32%

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

Large Power Service
Schedule 19 Primary TOU

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) % chg
1	Service Charge	1,213.7	$85.71	$104,026	$125.00	$151,713	45.8%
	Basic Charge						
2	Summer	1,103,973	0.77	850,059	$0.79	872,139	2.6%
3	Non-Summer	3,303,749	0.77	2,543,887	$0.79	2,609,962	2.6%
4	Total Basic Charge	4,407,722		3,393,946		3,482,101	2.6%
	Demand Charge						
5	Summer	970,688	2.65	2,572,323	2.76	2,679,099	4.2%
6	On-Peak Summer	957,681	0.00	0	0.36	344,765	new
7	Non-Summer	2,819,550	2.65	7,471,808	2.57	7,246,244	-3.0%
8	Total Demand Charge			10,044,131		10,270,108	2.2%
	Energy Charge						
9	On-peak	126,670,888	0.020839	2,639,695	0.025694	3,254,682	23.3%
10	Mid-peak	213,686,573	0.020839	4,453,014	0.023191	4,955,605	11.3%
11	Off-peak	150,424,746	0.020839	3,134,701	0.021616	3,251,581	3.7%
12	Summer Energy Charge	490,782,207		10,227,410		11,461,868	12.1%
13	Mid-Peak	843,585,690	0.020839	17,579,482	0.020978	17,696,741	0.7%
14	Off-peak	580,187,626	0.020839	12,090,530	0.020015	11,612,455	-4.0%
15	Non-Summer Energy Chrge	1,423,773,316		29,670,012		29,309,196	-1.2%
16	Total Energy Charge	1,914,555,523		39,897,422		40,771,064	2.2%
17	Customer Adj			(82,965)		(82,965)	0.0%
18	Total Billing			$53,356,560		$54,592,021	2.32%

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rate

Large Power Service
Schedule 19 Transmission TOU

		(1)	(2)	(3)	(4)	(5)	(6)
Line No	Description	Use	Current Base Rate	Current Base Revenue	Approved Base Rate	Approved Base Revenue	% chg
1	Service Charge	30.3	$85.71	$2,597	$125.00	$3,788	45.9%
	Basic Charge						
2	Summer	21,154	0.39	8,250	$0.40	8,462	2.6%
3	Non-Summer	81,683	0.39	31,856	$0.40	32,673	2.6%
4	Total Basic Charge	102,837		40,106		41,135	2.6%
	Demand Charge						
5	Summer	20,927	2.57	53,782	2.70	56,503	5.1%
6	On-Peak Summer	20,647	0.00	0	0.36	7,433	new
7	Non-Summer	75,313	2.57	193,554	2.51	189,036	-2.3%
8	Total Demand Charge			247,336		252,972	2.3%
	Energy Charge						
9	On-peak	2,857,632	0.020375	58,224	0.025337	72,404	24.4%
10	Mid-peak	5,424,997	0.020375	110,534	0.022869	124,064	12.2%
11	Off-peak	4,228,895	0.020375	86,164	0.021315	90,139	4.6%
12	Summer Energy Charge	12,511,524		254,922		286,607	12.4%
13	Mid-peak	23,817,182	0.020375	485,275	0.020643	491,658	1.3%
14	Off-peak	19,019,477	0.020375	387,522	0.019696	374,608	-3.3%
15	Non-Summer Energy Charge	42,836,659		872,797		866,266	-0.7%
16	Total Energy Charge	55,348,183		1,127,719		1,152,873	2.2%
17	Customer Adj.			7,282		7,282	0.0%
18	Total Billing			$1,425,040		$1,458,050	2.32%

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved (Six Months) Base Rates

Large Power Service
Schedule 19 Secondary

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) % chg
1	Service Charge	12.0	$5.54	$66	$5.60	$67	1.5%
	Basic Charge						
2	Summer	4,777	0.36	1,720	$0.37	1,767	2.7%
3	Non-Summer	13,918	0.36	5,010	$0.37	5,150	2.8%
4	Total Basic Charge	18,695		6,730		6,917	2.8%
	Demand Charge						
5	Summer	4,592	2.73	12,536	3.21	14,740	17.6%
6	On-Peak Summer	4,530	0.00	0	NA	0	NA
7	Non-Summer	12,400	2.73	33,852	2.64	32,736	-3.3%
8	Total Demand Charge			46,388		47,476	2.3%
	Energy Charge						
9	On-peak Summer	616,860	0.025576	15,777	0.028486	17,572	11.4%
10	Mid-peak Summer	1,063,953	0.025576	27,212	0.028486	30,308	11.4%
11	Off-peak Summer	693,552	0.025576	17,738	0.028486	19,757	11.4%
12	Total Summer Energy Charge	2,374,364		60,727		67,637	11.4%
13	Mid-peak Non-Summer	3,953,230	0.025576	101,108	0.025329	100,131	-1.0%
14	Off-peak Non-Summer	2,592,937	0.025576	66,317	0.025329	65,677	-1.0%
15	Total Non-Summer energy charge	6,546,167		167,425		165,808	-1.0%
16	Total Energy Charge	8,920,531		228,152		233,445	2.3%
17	Customer Adj.			637		637	0.0%
18	Total Billing			$281,973		$288,542	2.33%

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved (Six months) Base Rates

Large Power Service
Schedule 19 Primary

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) % chg
1	Service Charge	1,213.7	$85.71	$104,026	$125.00	$151,713	45.8%
	Basic Charge						
2	Summer	1,103,973	0.77	850,059	$0.79	872,139	2.6%
3	Non-Summer	3,303,749	0.77	2,543,887	$0.79	2,609,962	2.6%
4	Total Basic Charge	4,407,722		3,393,946		3,482,101	2.6%
	Demand Charge						
5	Summer	970,688	2.65	2,572,323	3.12	3,028,547	17.7%
6	On-Peak Summer	957,681	0.00	0	0.00	0	new
7	Non-Summer	2,819,550	2.65	7,471,808	2.57	7,246,244	-3.0%
8	Total Demand Charge			10,044,131		10,274,791	2.3%
	Energy Charge						
9	On-peak	126,670,888	0.020839	2,639,695	0.023403	2,964,479	12.3%
10	Mid-peak	213,686,573	0.020839	4,453,014	0.023403	5,000,907	12.3%
11	Off-peak	150,424,746	0.020839	3,134,701	0.023403	3,520,390	12.3%
12	Summer Energy Charge	490,782,207		10,227,410		11,485,776	12.3%
13	Mid-Peak	843,585,690	0.020839	17,579,482	0.020603	17,380,396	-1.1%
14	Off-peak	580,187,626	0.020839	12,090,530	0.020603	11,953,606	-1.1%
15	Non-Summer Energy Chrge	1,423,773,316		29,670,012		29,334,002	-1.1%
16	Total Energy Charge	1,914,555,523		39,897,422		40,819,778	2.3%
17	Customer Adj			(82,965)		(82,965)	0.0%
18	Total Billing			$53,356,560		$54,645,418	2.42%

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved (Six Months) Base Rates

Large Power Service
Schedule 19 Transmission

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) % chg
1	Service Charge	30.3	$85.71	$2,597	$125.00	$3,788	45.9%
	Basic Charge						
2	Summer	21,154	0.39	8,250	$0.40	8,462	2.6%
3	Non-Summer	81,683	0.39	31,856	$0.40	32,673	2.6%
4	Total Basic Charge	102,837		40,106		41,135	2.6%
	Demand Charge						
5	Summer	20,927	2.57	53,782	3.06	64,037	19.1%
6	On-Peak Summer	20,647	0.00	0	0.00	0	new
7	Non-Summer	75,313	2.57	193,554	2.51	189,036	-2.3%
8	Total Demand Charge			247,336		253,073	2.3%
	Energy Charge						
9	On-peak	2,857,632	0.020375	58,224	0.022957	65,603	12.7%
10	Mid-peak	5,424,997	0.020375	110,534	0.022957	124,542	12.7%
11	Off-peak	4,228,895	0.020375	86,164	0.022957	97,083	12.7%
12	Summer Energy Charge	12,511,524		254,922		287,228	12.7%
13	Mid-peak	23,817,182	0.020375	485,275	0.020241	482,084	-0.7%
14	Off-peak	19,019,477	0.020375	387,522	0.020241	384,973	-0.7%
15	Non-Summer Energy Charge	42,836,659		872,797		867,057	-0.7%
16	Total Energy Charge	55,348,183		1,127,719		1,154,285	2.4%
17	Customer Adj.			7,282		7,282	0.0%
18	Total Billing			$1,425,040		$1,459,563	2.42%

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

Agricultural Irrigation Service
Schedule 24 Secondary

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) % chg
1	Bills-In Season	57,726.6	$10.07	$581,307	$12.00	$692,719	19.17%
2	Bills-Out Season	106,476.3	2.50	266,191	3.00	319,429	20.00%
3	Minimum Charges	4,126.6	2.50	10,317	3.00	12,380	20.00%
		164,203					
	Demand Charge						
4	Total In-Season	3,040,024	3.58	10,883,286	$4.00	12,160,096	11.73%
5	Total Out-Season	3,514,904	0.00	0	0.80	2,811,923	
6	Total kW	6,554,928		10,883,286		14,972,019	37.57%
	Energy Charge						
7	Total In-Season	1,226,232,536	0.028416	34,844,624	0.032440	39,778,983	14.16%
8	Total Out-Season	312,462,422	0.036172	11,302,391	0.032440	10,136,281	-10.32%
9	Total kWh	1,538,694,958		46,147,015		49,915,264	8.17%
	sumer differential						0.00%
10	Customer Adj.			(392,596)		(392,596)	0.00%
11	Total Billing			$57,495,520		$65,519,215	13.96%

Idaho Power Company
Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

Agricultural Irrigation Service
Schedule 24 Transmission

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue
1	Bills-In Season	0.0	$10.07	$0	$12.00	$0
2	Bills-Out Season	0.0	2.50	0	3.00	0
3	Total In-Season	0	3.37	0	3.76	0
4	Total Out-Season	0	0.00	0	0.75	0
5	Total kW	0		0		0
6	Total In-Season	0	0.027021	0	0.030858	0
7	Total Out-Season	0	0.034396	0	0.030858	0
8	Total kWh	0		0		0
9	Customer Adj			0		0
10	Total Billing			$0		$0

Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

TOU Agricultural Irrigation Service
Schedule 25 Time of Use

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue	(6) % chg
1	In Season Charges	942.5	$10.07	$9,491	$12.00	$11,310	19.17%
2	Out Season Charges	1,311.7	2.50	3,279	3.00	3,935	20.01%
3	Meter Charge	942.5	3.00	2,828	3.00	2,828	0.00%
4	Minimum Charges	71.0	2.50	178	3.00	213	19.66%
	Demand Charge						
5	Total In-Season	164,121	3.58	587,553	4.00	656,484	11.73%
6	Total Out-Season	85,004	0.00	0	0.80	68,003	new
7	Total Demand Charge	249,125		587,553		724,487	23.31%
	Energy Charge						
8	On-peak	17,714,172	0.049728	880,890	0.058854	1,042,550	18.35%
9	Mid-peak	10,173,361	0.028416	289,086	0.033631	342,140	18.35%
10	Off-peak	36,669,735	0.014208	521,004	0.016815	616,602	18.35%
11	Out-season	17,678,705	0.036172	639,474	0.033631	594,553	-7.02%
12	Total Energy Charge	82,235,973		2,330,454		2,595,845	11.39%
13	Customer Adj			(31,793)		(31,793)	0.00%
14	Total Billing			$2,901,990		$3,306,825	13.95%

Idaho Power Company
Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates

Unmetered General Service
Schedule 40

Line No.	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue
1	Number of Bills	14,687.0				
	Minimum Charges	566.6	1.50	$850	1.50	$850
2	Total kWh	16,054,942	0.05680	911,921	0.05143	825,706
3	Customer Adj.			(5,082)		(5,082)
4	Total Billing			$907,689		$821,474

Idaho Power Company
Summary of Revenue Impact
Approved Base Rates
Street Lighting-Company Owned
Schedule 41
Non-Metered Service

Line No	Description	(1) Annual Lamps	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue
	Sodium Vapor					
1	100-Watt	168,346	6.37	1,072,364	5.69	957,889
2	200-Watt	23,907	7.44	177,868	6.65	158,982
3	250-Watt	1,098	8.42	9,245	7.53	8,268
4	400-Watt	1,008	10.60	10,685	9.48	9,556
5	Total Sodium Vapor	194,359		1,270,162		1,134,695
	Adjustment for City of Ketchum Contract					
6	70-Watt	238	7.07	1,683	6.32	1,504
7	100-Watt	636	7.64	4,859	6.83	4,344
8	Total City of Ketchum	874		6,542		5,848
9	Customer Adj			(33,115)		(33,115)
10	Non-Metered Company-Owned			1,243,589		1,107,428
11	Non-Metered Customer-Owned			565,680		562,034
12	Metered Company-Owned			0		0
13	Metered Customer-Owned			0		0
14	Total Street Lighting Revenue			1,809,269		1,669,462
15	Total Bills	1,420				
16	Total kWh	17,878,742				

Idaho Power Company
Summary of Revenue Impact
State of Idaho
Normalized 12-Months ending December 31, 2003
Approved Base Rates
Traffic Control Lighting
Schedule 42

Line No	Description	(1) Use	(2) Current Base Rate	(3) Current Base Revenue	(4) Approved Base Rate	(5) Approved Base Revenue
1	No. of Billings	696.0				
2	Traffic Lamps	9,384,218	$0.03105	$291,380	$0.03191	$299,450
3	Customer Adj.			(7,235)		(7,235)
4	Total Billing			$284,145		$292,215