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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 RATES AND CHARGES FOR ELECTRIC SERVICE TO ITS CUSTOMERS IN THE STATE OF IDAHO	)	**CASE NO. IPC-E-08-10** **ORDER NO. 30722**

ISSUED:

JANUARY 30, 2009

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This is a final Order establishing the revenue requirement and rates for Idaho Power Company's electric service in Idaho. Idaho Power filed an Application on June 27, 2008, requesting authority to increase its rates by 9.89% to recover an additional $66,588,286 in annual revenue for its Idaho operations. On July 21, 2008, the Commission issued Order No. 30600 suspending the proposed effective date of July 27, 2008 for the Company's new rates. *See Idaho Code* § 61-622. By this Order, we approve an increase in the Company's Idaho jurisdiction revenue requirement in the amount of $20,878,884 and authorize Idaho Power to increase its rates by an overall average of 3.10%. Electric base rates for specific customer classes will increase on average by the following percentages: Residential 1.61%; Small General Service .42%; Large General Service 3.35%; Industrial 5.62%; and Irrigation and Special Contract Customers 6%.

IDAHO POWER'S APPLICATION

Idaho Power used a 2008 test year to establish its requested rate increase. The test year data was based on actual 2007 account information, and the Company used projected increases to develop its 2008 test year. The Company requested that the Commission approve a return on rate base of 8.55%, utilizing an 11.25% return on common equity, on an Idaho retail rate base of $2,093,399,014. Exh. 46. The result would be an additional annual revenue requirement of $66,588,286 for its Idaho operations.

Based on a cost-of-service study filed with its Application, Idaho Power proposed various increases for the different customer classes. The Company proposed to increase rates for residential customers by 6.31% and increase the residential monthly service charge by $1. Idaho Power proposed to increase rates for small commercial customers by 10.63% and by 11.46% for large commercial customers. Finally, the Company's industrial customers, irrigation customers, and its three special contract customers – J.R. Simplot Company, the Department of Energy, and Micron Technology, Inc. – would see rates increase by 15% under the Company's proposed rate schedule.

Idaho Power also requested approval of adjustments to different rate components. For residential customers, the Company proposed to double the number of kilowatt-hours qualifying for the lower-cost, first block of energy and to increase the differential between the first and second block for energy charges during the summer months. Idaho Power proposed similar adjustments to the rates for small commercial customers. For large commercial customers, the Company would increase the service charge, the basic charge, the demand charges and the seasonal energy charges for these customers, and also implement mandatory time-of-use rates for commercial customers taking service at the primary and transmission service levels. Idaho Power proposed to increase the service charge, basic charge, and the seasonal and time-of-use demand charges and energy charges for the industrial customers. Finally, irrigation customers would see increases in their service charge, the demand charge, the in-season and out-of-season energy charges, and the Company also proposed introducing a load-factor-based pricing mechanism.

Idaho Power included in its case a request for a Commission finding that demand-side management program expenditures funded by an Energy Efficiency Rider during 2003-2007 were prudent. Staff in its prefiled testimony recommended the Commission defer a prudency determination until the Company provided a comprehensive evaluation of its programs and implementation efforts. On January 9, 2009, Idaho Power and Staff filed a Joint Motion to Defer Energy Efficiency Rider Prudency Determination. The Motion states that Staff and the Company intend to discuss their differences and "they believe that they may be able to reach agreement regarding the prudency of some or all of the Energy Efficiency Rider funds spent between 2003 and 2007."

No other party in the case presented testimony on the use of Energy Efficiency Rider funds or the prudency of programs funded by the rider, and no party objected to the Motion filed by Staff and the Company. The Commission grants the Joint Motion and defers a decision on the prudency of the demand-side management expenditures.

PARTIES OF RECORD, PROCEDURAL SCHEDULE

On July 21, 2008, the Commission issued a Notice of Application and Notice of Intervention Deadline and Order suspending the proposed effective date of July 27, 2008, for the Company's rate increase. Petitions to Intervene were filed by the Idaho Irrigation Pumpers Association, Inc. (Irrigators); the Industrial Customers of Idaho Power (Industrial Customers); Micron Technology, Inc. (Micron); the U.S. Department of Energy (DOE); The Kroger Company dba Fred Meyer and Smith's (Kroger); Community Action Partnership Association of Idaho (CAPAI); and the Snake River Alliance. The Commission granted each Petition to Intervene. *See* Order Nos. 30600 and 30620. Idaho Power and the Commission Staff are the other parties in the case.

On September 4, 2008, the Commission issued a Notice of Scheduling and Notice of Hearing establishing deadlines for completion of discovery and the filing of Staff and Intervenor testimony and rebuttal testimony. The Commission Staff convened public workshops in Pocatello, Twin Falls and Boise in October 2008 to inform customers of the Company's Application and rate proposals. In December 2008, the Commission convened public hearings in Pocatello, Twin Falls, and Boise to receive comment from customers. The technical hearing was held in the Commission's Hearing Room in Boise December 16-19, 2008. All parties appeared and were represented at the hearing.

COMMISSION OVERVIEW

The Commission is cognizant of Idaho Power's need to have adequate cash flow and provide a return for its shareholders. We note that calendar year 2009 will be the first full year that Idaho Power will experience the impacts of the general rate increase of 5.2% effective March 1, 2008, the separate rate increase for the Evander Andrews/Danskin unit effective June 1, 2008, and the Energy Efficiency Rider increase effective June 1, 2008. Each of these Commission decisions provides increased cash flow to Idaho Power to meet operating requirements and necessary capital expenditures. This base rate increase will also improve earned return on equity.

Rate increases are not the only means to increase earned return on equity. We expect Idaho Power to demonstrate its ongoing efforts to reduce operating costs and increase efficiencies. We caution the Company that in the current economic climate, Idaho Power's fiscal responsibility will be reviewed extensively and continually. It is incumbent upon Idaho Power to act judiciously in all phases of operations and maintenance and to document actions taken and assumptions made in coping with new realities. Such realities may result from emerging business downturns, job losses or ancillary impacts of a recessional economy. Company revenue requirements for capital expansion may also be impacted by extreme volatility in financial credit markets.

The Commission recognizes that the original filing date for this rate case was well before the precipitous economic changes. However, Commission decisions in this case occurred in the midst of the early economic downturn. The volatility of the market, and general financial distress on both a state and national level, have triggered significant Commission concern about ambitious financial projections of Idaho Power based on 2007 customer growth as extrapolated into a 2008 test year. These concerns are evidenced in the conservative decisions of the Commission. However, in looking proactively to the future, our Order establishes a 2008 forecast test year with rate base adjustments annualized as of December 31, 2008. Power supply costs are forecast to better match these costs with the time period rates will be effective. We have included in rates the Allowance for Funds Used During Construction (AFUDC) on the relicensing investment for the Hells Canyon Project. This increases cash flow and reduces regulatory risk. These decisions provide audit verification and customer protection that include only known and measurable costs.

The Commission is aware of the ongoing capital requirements of Idaho Power to meet loads and continue to provide safe, reliable services to Idaho customers. This Order does not stand alone as the Company and others analyze the ongoing risks the Company and its customers face. For example, the Commission approved the Fixed Cost Adjustment (FCA) mechanism to eliminate or reduce disincentives in rates that may have impacted DSM/Energy Efficiency. In Order No. 30715, the Commission approved the stipulated changes to the Power Cost Adjustment (PCA) that will increase cash flow, increase earnings and reduce the risk of Idaho Power. The specific changes include the reduction in the sharing percentage, the establishment of the Load Growth Adjustment Rate (LGAR) formula for customer growth and the use of updated information in forecast test year data and power cost distribution. All of these decisions improve cash flow and reduce volatility in reported earnings.

The record in this case indicates the Company's customer service center currently is staffed to effectively answer customer calls in a timely manner. Tr. pp. 1561-1567. The

Commission commends Idaho Power for improvements it has made in customer service facilities and staff. Timely and effective response to customer concerns is an important function of any utility, and we appreciate that Idaho Power takes this responsibility seriously.

Ultimately, the Commission must balance the best interests of Idaho Power customers and the Company's financial needs. When viewed in the context of the other decisions noted above, we believe our decisions in this rate case successfully accomplish that balance for both.

TEST YEAR

Idaho Power proposed a calendar year 2008 test year. The Company used an adjusted, historical 12-month period ending December 31, 2007 as the basis to develop its 2008 test year. The Company made what it determined to be "standard regulatory adjustments" to the 2007 actual data. These adjustments included removing structures and properties within plant held for future use for which the use is uncertain; removing expenses as previously directed by the Commission, such as general advertising expenses, specific memberships and contributions and certain management expenses; and removing portions of plant costs deemed not to be used and useful. Tr. pp. 2262-2263.

After completing adjustments to the 2007 base data, the Company used three methods to develop account levels for a 2008 test year. The three methods were: Use of compounded growth rate to project test year balances, making known and measurable adjustments, and annualizing adjustments. Tr. p. 2263. The growth rates were either three- or five-year compounded annual growth rates. These projected rates of growth were applied to investments less than $2 million, to certain operation and maintenance expenses and to annualizing adjustments. Tr. p. 2263. The Company made known and measurable adjustments for scheduled investments greater than $2 million. Finally, the Company made annualizing adjustments to some expense and rate base items to reflect them as though they had been in existence for the entire year, or at year-end levels. Annualizing adjustments include year-end payroll, incentive pay, the 2009 salary structure adjustment, depreciation expense and reserve, plant placed in service during 2008 that exceeded $2 million and Company-directed spending containment. Tr. pp. 2263-2264.

Staff recommended several adjustments to the 2007 year actual data as adjusted by the Company. Staff and some intervenors also raised objections to the Company's development of 2008 test year account balances, primarily in the Company's use of growth rate projections applied to certain accounts. The Industrial Customers characterized the Company's 2008 test year as being "fully forecasted" and stated its opposition to a forecasted test year because "the assumptions and projections made by the Company may or may not in fact come true." Tr. p. 2420. The Industrial Customers noted, however, that the timing of the case enabled the parties and Commission to compare the Company's projections with actual results for most of 2008. The Industrial Customers recognized that the availability of actual results for nine months in 2008 would enable the Commission to set rates using financial data "that is closer to actual rather than a full 12-month projection." Tr. p. 2425.

Micron also raised concerns about Idaho Power's use of projections to develop its 2008 test year, testifying that "the type of general, across-the-board expense increases Idaho Power is forecasting in this case are too unreliable for use in ratemaking, and that they are likely to be biased in the Company's favor as well." Tr. p. 1678. Micron also noted that the current economic situation is completely different from when the Company prepared its case in the spring of 2008. Micron testified that the current economic climate "makes Idaho Power's forecasted test year, which is premised upon a continuation of steady system load growth and further rapid climb in already high costs, implausible to point of impossibility." Tr. p. 1677. Micron testified, in these circumstances, "The most accurate method would be to use the normal 2007 historical test year, adjusted for known and measurable changes." Tr. p. 1679.

The Staff generally accepted Idaho Power's methodology to develop a 2008 test year that begins with actual 2007 calendar year costs updated through December 31, 2008. Tr. p. 1590. Staff supported including major plant addition in excess of $2 million expected to be completed prior to December 31, 2008, and annualizing those plant additions as if they were in service for the entire year. Staff also supported some of the Company's proposed escalation of expense and capital accounts on the basis of a compounded annual growth rate. Tr. pp. 1590-1591. Staff analyzed specific accounts and recommended that escalation be limited to select accounts where a specific trend can be identified, and where expenses do not depend significantly on management discretion. Staff raised no objection to the Company's use of forecasted 2008 customer totals to establish annual variable power supply costs.

Staff's approach to the Company's test year was "to balance the need for timely cost recovery with the Commission's obligation to audit and verify that costs have been or will be reasonably incurred." Tr. p. 1593. Staff testified that the Company's choice of escalator and some of the accounts chosen for escalation did not reasonably meet a "known and measurable cost standard." Tr. p. 1591. Micron also objected to the Company's use of escalators that Micron described as "percentage inflators that are shockingly high by any measurement." Tr. p. 1687.

The Commission finds it reasonable and appropriate to adopt a 2008 test year in this case. We also find appropriate the Company's use of 2007 actual data, with adjustments, to form a basis for developing its 2008 test year. We do not accept, however, all of the Company's 2007 adjustments, or all of the forecasted account projections as proposed by the Company. Included in the duty to provide timely rate relief to Idaho Power, the Commission has a parallel responsibility to ensure that customer rates are based on expenditures that are reasonable and prudently incurred.

The Commission accepts the forecasted increases in 2008 test year account balances to which no specific objection was raised. These adjustments to the 2008 test year include the addition of major plant investment in excess of $2 million that was completed by December 31, 2008 and the Company's proposed escalation of some expense and capital accounts. Rather than accept all of the Company's proposed escalation adjustments, the Commission reviewed the specific account information to determine whether the Company's proposed escalations are reasonable. Available information includes 2008 actual account information. By reviewing the data underlying the Company's proposed escalator and, where appropriate, comparing the Company's projected account increases with the available 2008 actual information. The Commission determined the revenue and expense adjustments that are appropriate for the 2008 test year.

RATE BASE

The regulatory adjustments Idaho Power made to the 2007 rate base account balances included removal of an unamortized portion of electric plant amortization adjustment associated with the Prairie Power Rural Electric Cooperative purchase, and removal of plant deemed not used and useful at the Bridger Coal facility. Tr. p. 2262. The adjustments the Company made to determine rate base for the 2008 test year included use of compound growth rates to project account balances at the end of 2008, making known and measurable adjustments, and annualizing some plant balances. For plant investment of less than $2 million, the Company used a three-year compounded growth rate to project account balances at the end of 2008. The

Company made known and measurable adjustments for plant investment greater than $2 million that were expected to be completed by the end of the test year, and annualized these plant additions to reflect them as though they had been in existence for the entire 2008 test year. By this process, Idaho Power determined its 2007 actual rate base as adjusted to be $1,980,176,049, and projected a total system rate base at December 31, 2008 of $2,265,781,563, and a rate base for its Idaho jurisdiction of $2,093,398,859. Exhs. 39; 46.

Very few specific objections were raised to Idaho Power's determination of a 2008 test year rate base. Although expressing reservation about the Company's proposed escalation in capital expenditures of less than $2 million, Staff generally accepted the Company's approach to determine 2008 test year plant account balances. Staff did not propose adjustments to these expenditures in the test year rate base, but testified that the methodology, if continued into the future, will eventually result in unreasonable compounding of additions to rate base. Tr. p. 1283. Staff recommended the Company continue to evaluate more appropriate methods to establish known and measurable rate base levels for capital investments of less than $2 million. Tr. p. 1283. Staff raised no objection to the Company's placement in the test year of plant investment greater than $2 million.

Micron did not contest adding plant investment greater than $2 million completed by year-end to rate base, but did generally contest Idaho Power's annualization of these larger capital investments. Micron testified that although "such annualizing adjustments may be appropriate for an historic test period . . . they are totally inappropriate for a future test period." Tr. p. 1690. Noting that the Company proposed only $1,489,324 in annual revenue associated with the plant additions, Micron testified that the Company's "proposed 'matching' of annualized costs and revenues comes out in favor of shareholders over ratepayers by a factor of nine to one." Tr. pp. 1691-1692. Micron urged the Commission to deny Idaho Power's proposed $91.3 million plant annualization adjustment. Tr. p. 1693. In rebuttal testimony, Idaho Power noted that it matched plant investment and revenues by imputing revenue for more than one-half the annualized plant, consistent with previous Commission directives, and that 41% of the annualized plant is categorized as reliability- or compliance-related and as such has no revenue-producing capability. Tr. p. 2313.

The Commission accepts the adjustments Idaho Power made to the test year rate base to add capital investments of less than $2 million, and to add and annualize actual investments greater than $2 million. Staff reviewed the group of smaller investments as projected for 2008 and determined the projected balances are reasonable for what was anticipated to be actual costs by the end of the year. The Commission's acceptance of this adjustment should not be seen as a blanket endorsement of the forecast methodology used to add smaller plant costs to test year rate base. The burden remains on the Company to demonstrate that its proposed test year balances represent known and measurable expenditures.

Staff identified two specific adjustments it believes are appropriate to the Company's proposed rate base. Early in 2008, Idaho Power filed a case addressing the annual depreciation rates for the Company's capital assets, Case No. IPC-E-08-06. The Commission approved new depreciation rates for Idaho Power, but did not issue its Order until September 12, 2008, approximately 2½ months after the Company filed its Application in this case. Staff noted that the new depreciation rates change the Company's anticipated depreciation expense from a $471,026 increase to a $1,000,163 decrease, thus reducing depreciation expense by $1,471,189. Tr. p. 1276. This expense affects the accumulated depreciation account, which is a rate base account. Staff testified that the net effect on the depreciation reserve account is a decrease in the reserve account balance of $735,595. Tr. p. 1278. Because a reduction in the depreciation reserve account creates a corresponding increase in rate base, Staff recommended an increase in Idaho Power's rate base in the same amount. In its rebuttal testimony, Idaho Power agreed with this adjustment to rate base proposed by Staff. Tr. p. 2313.

The Commission finds the adjustment to Idaho Power's 2008 test year rate base to account for current depreciation rates is appropriate. The Company determined its accumulated depreciation balance using depreciation rates in effect at the time it filed its Application. Those rates were changed by Commission Order in September 2008, and the Company recognized in its rebuttal testimony that the adjustment proposed by Staff to the accumulated depreciation account balance is appropriate. The Commission therefore approves a reduction in the 2008 test year accumulated depreciation account balance of $735,594 to be reasonable and appropriate.

The other adjustment to the Company's 2008 test year rate base recommended by Staff has to do with the Company's proposed increase to the 2007 plant material and supply account. The Company projected an increase in the account balance of $6,617,514 over the 2007 account balance. This account reflects the inventory of materials used for the construction, operation, and maintenance of the Company's utility plant. Staff testified the Company's projected increase cannot be considered known and measurable with a degree of certainty because the balance of the inventory account depends upon current conditions. Staff stated a belief that "adequate planning, ordering, and inventory management will allow inventory levels to be maintained at 2007 levels." Tr. p. 1308.

The Commission finds that the 2008 test year balance for the plant material and supplies account as proposed by Idaho Power is appropriate. The Commission was able to test the reasonableness of the Company's proposed increase in the account balance by comparing the projected balance with the actual account balance as of October 2008. The Company projected a 2008 amount for these inventory accounts to be $50,128,526, and the actual balance through October 2008 was $50,407,997. Tr. p. 2336. Inventory costs fluctuate month to month and are affected by customer growth. Although the Company anticipates slower customer growth for 2008, we find that the balance for plant materials and supplies as projected by the Company in the test year is reasonable.

Making the adjustment to the test year rate base to reflect current depreciation rates, and accepting the Company's other rate base adjustments, results in a test year rate base of $2,094,082,620 for the Company's Idaho operations.

ADJUSTMENTS TO TEST YEAR REVENUE AND EXPENSES

Idaho Power determined revenues and expenses for its 2008 test year in the same way it established a test year rate base. The Company started with 2007 actual figures and made adjustments to specific revenue and expense accounts it deemed appropriate for regulatory purposes. With the 2007 accounts established, the Company next considered different ways "to adjust auditable historic data to establish the 2008 test year that would be representative of the Company's anticipated levels of spending." Tr. p. 2278. For some account groupings, the Company elected to use a "three or five-year compounded annual growth rate, which is the average growth rate over the number of years that represents a steady level of growth from the beginning period to the ending period and smoothes out uneven amounts within these years." Tr. p. 2281. For a small number of accounts, Idaho Power determined that a trending multiplier was not appropriate and so used the adjusted 2007 actual figures for those accounts in the 2008 test year. Tr. pp. 2279-2280.

Staff and other parties raised some objections to the Company's adjustments to the 2007 actual revenue and expense items, as well as to the Company's projected account balances for the 2008 test year. Whether to the 2007 actual balances or to the 2008 test year projections, all of the challenges and recommended account adjustments affect the test year revenue requirement. Accordingly, the Commission will review the adjustments as they affect test year revenues and expenses.

Allowance for Funds Used During Construction

Idaho Power proposed to include in its revenue requirement a component that until recently could not have been reflected in its revenue requirement. *Idaho Code* § 61-502A, enacted in 1984, prohibited the Commission from "setting rates for any utility that grants a return on construction work in progress [CWIP] or property held for future use and which is not currently used and useful in providing utility service," unless the Commission determined that an "extreme emergency" existed. When CWIP is not included in rate base, however, the Commission is required to "allow a just, fair and reasonable allowance for funds used during construction [AFUDC] or similar account to be accumulated, computed in accordance with generally accepted accounting principles." *Idaho Code* § 61-502A. The statute was amended in 2006 to allow CWIP in rates if the Commission makes an "explicit finding that the public interest will be served thereby." The provision regarding AFUDC was unchanged. Idaho Power proposed that a portion of the AFUDC component of CWIP for the Hells Canyon relicensing project be included in base rates.

Idaho Power began incurring Hells Canyon relicensing costs in 1999. Tr. p. 333. The Company explained that relicensing efforts are financed from internally generated funds and from outside sources including short-term debt, long-term debt and new equity. Tr. p. 333. The Company accrues and capitalizes these financing costs to Account 107 as AFUDC during the project. AFUDC is calculated monthly using a rate determined by a FERC formula, but is not collected in rates while it accumulates. Once the construction project is complete, the construction costs and total AFUDC amount are placed in rate base. As of December 31, 2007, the Hells Canyon relicensing costs included in FERC Account 107 totaled $95.6 million. AFUDC comprised 30%, or $27.9 million of the total amount.

Idaho Power did not request that Hells Canyon CWIP be included in rate base, but did request that payment of estimated financing costs (AFUDC) be allowed in rates as they are incurred in 2009. The Company requested that $7.6 million be included in base rates to fund the ongoing financing costs associated with the Hells Canyon relicensing project. Tr. p. 336. The

Company estimated that $7.6 million is the amount needed to offset the anticipated annual growth of AFUDC. The Company estimated that 2008 and 2009 AFUDC will be $7.1 million and $7.6 million, respectively, and that by year end 2009, the total accumulated AFUDC will be $42.7 million or 42% of the total CWIP related to the Hells Canyon relicensing. Tr. p. 337; Exh. 35.

Staff generally agreed with the Company's proposal to include the 2009 AFUDC in base rates. Staff stated that the AFUDC related to the Hells Canyon relicensing project is growing at an alarming rate, and that "this case provides an appropriate opportunity where the Commission can find that the public interest will be served by the inclusion of the currently accruing AFUDC on the Hells Canyon relicensing project." Tr. p. 1310. If AFUDC continues to accrue, and assuming no additional expenses are incurred on the relicensing project, the direct cost for the project would be $67,682,931 and AFUDC would equal $42,703,648 by the end of 2009. Tr. p. 1310. By the end of 2012, AFUDC would grow to $69,188,894 even if direct costs of relicensing remained at $67,682,931. Exh. 123.

Staff supported including AFUDC on the Hells Canyon relicensing project because licensing these hydro facilities is different than most construction projects. Staff noted that completion of the project is largely beyond Idaho Power's control. In addition, it is unlikely the permanent license will not be granted, and in the meantime, the Hells Canyon Complex is fully operational and is producing power. Staff accepts that the relicensing investment is essentially used and useful at the present time. Tr. p. 1315.

Staff did recommend adjustments to the amount for AFUDC that Idaho Power requested to be included in rates. Using AFUDC rates for 2008 supplied by the Company, Staff calculated the 2008 AFUDC rate and the estimated AFUDC dollar amount for 2009 based on the CWIP balance at December 2008. Staff determined that the AFUDC level for 2009 was $4,754,292, or $2,881,849 less than calculated by the Company. Staff recommended the amount of AFUDC included in revenue requirement to be the $4.7 million for AFUDC that Staff calculated. Tr. p. 1312. Staff agreed with the Company's proposal to account for collected AFUDC funds as a regulatory liability, and recommended that interest accrue on that liability account at the same rate as AFUDC that is booked as CWIP. Tr. p. 1313. Staff also recommended that the AFUDC included in rates terminate at December 31, 2009, unless the Company files an application to continue collecting AFUDC in rates. Tr. p. 1314.

Micron opposed Idaho Power's proposal to include the 2009 AFUDC cost of $7.6 million in rates. Micron noted that state utility commissions have the duty to regulate utilities in a manner that imposes financial discipline and operating efficiencies that otherwise would be provided by competitors or the threat of competition. Tr. p. 1695. Commissions use the disallowance of imprudently-incurred expenses and non-productive capital investments in rates to replicate the effects of competition. If AFUDC is included in rates, Micron argued that the competitive effect imposed by utility commissions is lost. Micron argued that if the Commission "forcibly extracts compensation from the public for good and bad performance alike, there is no incentive to perform." Tr. p. 1697. Micron testified that the regulatory account the ratepayers would get if AFUDC is included in rates amounts to a 30-year unsecured loan at 0% interest. Tr. p. 1699.

In rebuttal testimony, Idaho Power addressed Micron's objections to including AFUDC in rates and Staff's calculation of 2009 AFUDC expense. Staff estimated an AFUDC rate of 4.759% for 2008 based on the average rate from the first eight months of the year. Idaho Power noted that for October 2008 the AFUDC rate was 6.585%, and asserted the 2007 AFUDC average rate of 7.19 was the best estimate of the AFUDC rate for 2009. Tr. pp. 346-347. Idaho Power also testified that Staff's calculation of 2009 AFUDC expense was in error by not allowing for the normal compounding that occurs as AFUDC accrues. Tr. p. 348. The Company also disagreed with Staff's recommendation that the collection of AFUDC in rates terminate December 2009. The Company argued it has no control over the date that a permanent license for Hells Canyon is granted. AFUDC will continue to accrue until the license is granted and the project costs are included in rate base. The collection of 2009 AFUDC would not contribute to the Company's profitability, but would improve its cash flow. Idaho Power asserted this is necessary to maintain its credit strength in order to access competitive lending markets for construction project funding. Tr. p. 350.

The Commission finds that the Hells Canyon relicensing project is unlike a typical construction project, and establishes circumstances that support a finding that including AFUDC in rates will serve the public interest. The unique circumstances include: (1) the project process has already been under way for nearly ten years, and Idaho Power has little control over the completion date; (2) the Company is able to use the generating facilities during the relicensing process, and they currently provide a significant amount of the Company's total generating capacity and energy; (3) the lengthy duration of the project, and an as yet unknown completion date, mean that AFUDC is already significant and will continue to accumulate to alarming levels. Other considerations, not unique to the Hells Canyon project, also support a finding the public interest is served by including a portion of AFUDC in rates. The amount of AFUDC included in rates now will reduce the total project costs that ultimately will be included in rate base, thereby reducing future rate increases. Idaho Power's cash flow will improve, which will help maintain its credit strength and ability to access funds for ongoing construction projects.

The record in this case demonstrates unique circumstances for the Commission to consider including AFUDC in rates, and we find the Company's proposal to include 2009 AFUDC for the Hells Canyon relicensing project in rates to be in the public interest. The $6,815,472 amount we believe is appropriate to include in rates is based on the actual December 2008 AFUDC rate of 6.793% and the December 2008 CWIP balance. This rate fairly reflects current conditions. The Company shall file an AFUDC status report with the Commission by November 15, 2009. The report should state the completion date of the project, if it is completed, and provide closing entries and regulatory liability balance to date. If the project is not completed, the report should explain Idaho Power's efforts to complete the Hells Canyon relicensing process. It should also provide updated evidence to support continued collection of AFUDC in rates beyond December 31, 2009.

Adjustments to Employee Compensation Accounts

Idaho Power accrued $9,423,443 for employee incentive compensation in 2007 and used an escalator of 9.41% to project an accrual for incentive pay for the 2008 test year of $10,309,981. Because the Company determined its actual incentive expense for 2008 to be $6,418,111, it reduced its projected test year expense by $3,838,832. Exh. 31, p. 2. Staff recommended a further reduction to the incentive expense of $3,208,964, leaving $3.2 million in the test year for employee incentive compensation. Tr. pp. 1266-1268.

Staff's proposed reduction to incentive pay expense was based on a stipulation filed by Staff and Idaho Power in the Company's 2005 rate case, Case No. IPC-E-05-28, where it was agreed that "it is reasonable to include an employee pay-at-risk or employee incentive component in test-year revenue requirements so long as such incentive component is based on goals that benefit customers and the amounts payable for achieving the goals are limited to reasonable 'target' or medium goals." Tr. p. 1268. The Company calculated incentive pay at 4%

of the annual payroll expense associated with employees eligible to receive incentive compensation. Staff asserted that of the four target goals identified by the Company for incentive pay accrual, only Customer Satisfaction and Network Reliability are based on customer benefits. These two incentive goals support an incentive accrual of 2.5% of payroll rather than the 4% included by Idaho Power. Tr. p. 1268. Staff further reduced its recommended incentive accrual to 2%, noting that employees are not entitled to incentive compensation unless shareholders receive a dividend of $1.20 per share each year. Tr. pp. 1269-1271. Staff testified that this requirement ties incentive pay to a shareholder benefit that controls the incentive payout and that, accordingly, "the payment of the incentive is not based solely on goals that benefit customers." Tr. pp. 1269-1271.

In rebuttal testimony, Idaho Power asserted that the two percent target incentive related to Operations and Maintenance budget management should not be removed from the incentive pay accrual calculation. The Company testified that customers receive "the direct benefit of cost management" because "the Company is in the position of managing rising costs to the best of its ability and filing rate cases every one to two years, the benefits of budget management are reflected in rates on an ongoing basis." Tr. p. 2533. In response to Staff's proposal to reduce the incentive accrual by one-half percent because incentive pay is not distributed unless shareholders receive a threshold dividend, the Company stated that "the $1.20 threshold recognizes that if the Company's finances are such that it does not earn enough to make its dividend payment, then employee incentives should not be paid." Tr. p. 2534.

The Commission finds that an incentive pay accrual for the 2008 test year in the amount of $3,164,811 is just, fair and reasonable. We note initially that the 2007 incentive accrual exceeded the actual incentive pay anticipated for 2008 by nearly 41%, raising questions about the Company's calculation of the appropriate incentive pay amount. As we did in approving the stipulation in Idaho Power's 2005 rate case, the Commission affirms that incentive pay is properly included in annual revenue requirement if it is related to identifiable customer benefits. We find Staff's recommended adjustments to the 2008 test year incentive accrual appropriate so that employee incentive pay in the revenue requirement is directly related to improving service or reducing costs to customers. The Company's argument that customers benefit by O&M budget management that is reflected in rates set in annual rate cases does not create the necessary nexus between incentive pay and customer benefit.

Staff also recommended the Company's proposed Salary Structure Adjustment, a pay increase of 3% for employees in 2009, be removed from the 2008 test year. Staff asserted that this proposed adjustment in excess of $3 million is not known or measurable because a salary increase had not been approved for 2009. Economic conditions that developed since the Company filed its Application, Staff suggested, meant the Company should forego employee raises "for reasons of economic prudency." Tr. pp. 1271-1272. Idaho Power in rebuttal testimony stated that its Board of Directors approved a 3% Salary Structure Adjustment, effective December 27, 2008, at its November 2008 meeting. Tr. p. 2531. The Company testified that the pay increases were necessary to retain qualified employees, even in the current economic climate. On this record, the Commission finds that a Salary Structure Adjustment of 3% is known and measurable and is appropriately included in the 2008 test year.

Attorney Fees, Architect Services, Out-of-Period and Miscellaneous Expenses

Staff's recommended adjustments to test year expenses for attorney fees, architect services, out-of-period expenses and miscellaneous expenses are small and thus have very little impact on the projected revenue requirement. Staff recommended the 2007 expenses be reduced by $192,364 to remove attorney fees relating to stock plans for Idaho Power and its holding company, IDACORP. Tr. p. 1278; Exh. 118. Staff testified that these legal fees "related only to the stock plans of the companies and were separated from other legal services that were provided by the same firm." *Id.*

Idaho Power in rebuttal testimony disputed the reduction in attorney fee expense recommended by Staff. The Company contends the invoices labeled "Stock Plans" include "work on legal compliance issues associated with the Company's 401(k) and restricted stock plans for its employees." Tr. p. 2349. Without providing additional information, the Company asserted it had already reduced the invoiced amounts shown in Exhibit 118 to allocate a portion of the legal fees to IDACORP. Tr. pp. 2349-2350. In addition, Idaho Power "has requested that [the law firm] revise its invoice descriptions to avoid future misunderstandings of this type." Tr. p. 2350.

On this record, the Commission approves the adjustment to legal services expense to reduce the test year expenses by $192,364. When the invoice description is "Stock Plans (IPCO and IDACORP)," as shown in Exhibit 118, it is reasonable to conclude the services rendered were for company shareholder purposes. The burden is on Idaho Power to provide adequate information in the record to support its contention the services benefited customers and should be included in the annual revenue requirement.

Staff recommended a reduction in 2007 base year Account 923 – Outside Services expense to account for architectural services that should be capitalized rather than expensed. Staff recommended the amount of these services, $36,375, be removed from the 2007 base year expenses, thereby reducing the annual revenue requirement. Tr. pp. 1247-1248. Idaho Power disputed this adjustment, stating that the architectural firm provided consulting services, and that its consulting services "resulted in the decision to relocate approximately 20 percent of the Company's employees from the Corporate Office to the Boise Plaza building and thus defer a long-term decision on building new facilities." Tr. pp. 2347-2348. The Company disputed Staff's assertion that these costs should be capitalized, stating that capital expenditures "are not normal, recurring expenses and are costs that benefit the operations of more than one operating period," as well as "costs that improve the efficiency or extend the life of an asset." Tr. p. 2348. The Commission cannot find from the Company's response that these architectural services should be expensed rather than capitalized and amortized. We approve the adjustment recommended by Staff. However, we conclude a three-year amortization is appropriate and include the annual amortization of $12,125 in rates.

Staff recommended the 2007 base year expenses be reduced by $7,150 to remove expenses for travel alarm clocks, candy and contributions to different business or social organizations. Tr. p. 1251. In rebuttal testimony or at hearing, Staff and the Company each conceded error in determining whether the contributions to organizations had been properly removed, resulting in agreement on the treatment of $4,625 of Staff's $7,150 proposed adjustment. Tr. p. 2345. Thus, only expenses for candy and travel alarm clocks, $2,525 of the amount, remains for resolution. Idaho Power explained that the alarm clocks "were given out at the EEI Fall Financial Conference to assist in reminding security analysts (both fixed-income or debt, and equity) that Idaho Power is a viable and prudent investment option." Tr. p. 2343. The candy expense was for Butter Toffee given to "city and county agencies for providing information, data and assistance with easements, GIS data, and other documentation to Idaho Power," to help maintain city and county relationships. Tr. p. 2344.

Although Idaho Power describes its clock and candy donations as having "a definite business purpose and benefit," the Commission finds that these costs are not sufficiently related to providing service to customers that customers should pay for them. Accordingly, we approve a reduction in the 2007 base year expenses in the amount of $2,525, in addition to removal of the contributions to organizations that were no longer disputed.

Staff recommended an adjustment to 2007 year FERC Account 928, where regulatory fees and assessments are accrued. Staff recommended $163,901 be removed from the 2007 expenses as amounts that were actually accruals for months before or after 2007. Staff's Exhibit 110 indicates the beginning accrual for this account in 2007 was $480,505. This is also the starting number for 2007 in Company exhibits, and thus is the appropriate amount to include in 2007 expenses. Accordingly, we do not make Staff's recommended adjustment to reduce this amount.

Miscellaneous Service Revenue Adjustment

The Miscellaneous Service Revenues Account 451 includes fees collected from customers for various services, such as for changing, connecting or disconnecting service, and for charges like return trip charges and returned check fees. Exh. 34, p. 2. Applying a three-year annual growth rate to the account, Idaho Power projected a reduction of 13.99% in the revenues from the 2007 actual balance to the 2008 test year. Tr. p. 1262. The Company collected $4,050,513 of these miscellaneous revenues in 2007, but reduced the account by $566,667 to the amount of $3,483,846 for its test year. *Id.* According to Staff's testimony, the Company attributed the anticipated reduction in revenues to slower customer growth. *Id.* Staff contested the Company's reduction in the test year and recommended the 2007 actual revenue balance be used, thereby decreasing the Company's revenue deficiency by $566,667. *Id.* Idaho Power did not respond specifically to Staff's recommendation.

The Commission finds that the most appropriate balance for the 2008 test year for the Miscellaneous Service Revenues account to be the 2007 actual collections of $4,050,513. There is no evidence presented to support a correlation between customer growth and miscellaneous fee collections, and Idaho Power's argument that slower customer growth will reduce the revenues. In fact, Exhibit 113 shows that these collections decreased during 2005-2007 while the number of customers was steadily increasing. Tr. p. 2310. The miscellaneous revenues steadily increased from 2000 through 2005, and declined only during the last two years (2006-2007). Exh. 113. Had Idaho Power used a five-year growth rate for this account, the escalator it used for many accounts, the test year revenue would have been projected to increase by 19%.

Exh. 113. Finally, Exhibit 114 reveals that through the first half of 2008, the Company collected 49.9% of the total revenues collected during 2007, making it on target to match the 2007 miscellaneous revenue collections. On this record, we find the adjustment to add $566,667 to the Company's 2008 test year to be fair and reasonable.

FERC Credit Adjustment

Fees Idaho Power paid to the Federal Energy Regulatory Commission and to other federal agencies were included for recovery in customer rates in the Company's 2003 and 2005 rate cases. In 2006, after a legal challenge to the fee amounts, Idaho Power received a reimbursement of $3,266,010 for fees over-collected by these federal agencies during 1999-2006. Tr. pp. 1316, 2346. Because Idaho Power's customers paid the fees, Staff testified that the amount credited back to the Company for federal agency fees should benefit customers. Staff recommended the $3,266,010 amount be amortized over five years, resulting in a reduction in the Company's annual revenue requirement in the amount of $653,202. Tr. p. 1316.

In rebuttal, Idaho Power argues Staff's assertion that the Company overcollected its expenses in prior years could be true only if the Company had "over-earned" during the period in question. Tr. p. 2346. Because the Company's actual return on equity was below the allowed return on equity established in the 2003 and 2005 rate cases, Idaho Power contends it did not "over-earn" and should not have to repay the amount overcollected from customers. Tr. p. 2346. The Company also argued that Staff's proposed amortization is based on an assumption "that the Company has overcollected on an expense item for a prior period," and if approved would "simply cause the Company to under-earn." Tr. pp. 2346-2347.

Idaho Power does not dispute that it included in rates $3,266,010 for collection from customers to pay fees it ultimately did not have to pay. Its arguments to retain that amount rather than returning it in some form to ratepayers are unpersuasive. The Commission finds the amount overcollected from customers should be amortized over five years, reducing annual revenue requirement by $653,202 during that period.

Net Power Supply Expenses

The Commission determines the normal or expected annual power supply costs for Idaho Power in a general rate case and incorporates recovery of those costs in base rates. Actual power supply costs that vary from the normal amount included in rates are captured each year through the Company's PCA. Total power supply costs include fuel to operate the Company's coal and gas generating facilities, purchased power expenses, and purchases from PURPA qualifying facilities. Surplus power sales are subtracted from the total costs. Variable power supply expenses, or net power supply costs, are the sum of fuel expenses and purchased power expenses (excluding PURPA power purchases), minus surplus sales revenues. For ratemaking purposes, PURPA expenses are quantified separately from net power supply costs. The expected or normalized power supply costs are determined by a cost model that includes water conditions during the past 80 years and natural gas prices as computer program inputs. The PURPA expenses are fixed inputs to the power supply modeling and thus do not affect the variable power costs as determined by the model. Idaho Power proposed a net power supply expense for its 2008 test year of $91,472,564, comprised of fuel expense of $140,504,952 (coal and gas), plus purchased power costs of $58,126,719, minus power sales of $110,210,425 (and adding transmission losses of $3,051,318). The Company estimated PURPA purchases to be $63.3 million.

Staff recommended a net power supply cost of $80,243,253 (including transmission losses), approximately $11.2 million less than the Company's projection. Exh. 104. Staff testified "that Idaho Power's net power supply cost recommendations are too high because of inaccurate assumptions made by the Company regarding natural gas fuel prices used in AURORA, the model used for computing net power supply costs." Tr. p. 1169. Staff used a natural gas price of $7.75 per MMBtu in the AURORA model. Tr. p. 1168. Idaho Power determined a gas price of $7.74 per MMBtu, only a penny less than Staff's price, but the Company assigned different gas prices to some of the 80 water years when making its model run. Staff testified that the Company assigned a higher gas price to the lowest water year on record and assigned a lower price to the highest water year, based on an assumption that high gas prices are associated with low water conditions and that low gas prices occur when water conditions are high. Tr. p. 1171. Because Staff found no correlation between water conditions and gas prices, Staff used a gas price of $7.75 for all 80 water years in the model run. Tr. p. 1176. Staff also was able to use more recent gas price projections than were available to Idaho Power to determine its gas price input.

Micron challenged the Company's calculation of net power supply costs based on more recent gas prices and price projections. Noting that October 2008 gas prices and current gas price forecasts were less than $7 per MMBtu, Micron testified that "use of the current natural gas prices in the net power supply expense model would eliminate all or a very substantial portion of the forecasted expenses for the test year." Tr. p. 1681.

In rebuttal testimony, the Company explained that lower gas prices mean lower power market prices and in the power supply model, lower market prices increase Idaho Power's net power supply expense on a normalized basis. Tr. p. 438. The Company also explained that it believes the "AURORA modeling considers the gas price influence on electricity market prices too heavily and the water condition influence on electricity market price too lightly." Tr. p. 431. The Company accordingly segments the 80 years of water condition scenarios into five pentiles, and "adjusts gas prices in each of the pentiles as a surrogate for water condition influences on electricity prices." Tr. p. 432. By this process, the Company corrects what it believes is a modeling deficiency "by modifying the model driver, gas price." Tr. p. 432.

The Commission finds that the net power supply cost to be included in the revenue requirement in this case is the amount calculated by Staff. We cannot conclude from the evidence provided that the model has the deficiency described by the Company, or that its method of addressing the alleged deficiency is sound.

Adjustments to Operations and Maintenance Accounts

One of the most significant adjustments the Company made to its test year expense projections was to the Other Operations and Maintenance (O&M) account group. These accounts are assigned FERC account numbers 500 through 935. Staff Exhibit 119, a schedule provided by Idaho Power in Audit Response No. 53, shows its calculation of compounded annual growth rates for the O&M accounts. The Company compared individual account balances at year-end 2003 and 2007 for the different O&M accounts to establish a five-year growth rate for each group. For example, for the O&M steam expense accounts numbered 500-515, the 2007 year-end balance was 7.14% higher than the 2003 year-end balance. Exh. 119, p. 1, l. 7. Idaho Power thus proposed an overall increase for these accounts of 7.14% for its 2008 test year.

The Company's projected test year increase for all the O&M accounts was an average of 5.82%. Exh. 119, p. 3, l. 86. The total O&M amount for 2007 was $261.9 million. By applying its growth rate factor to the different O&M group accounts, the Company proposed a 2008 test year O&M amount of $277,129,738, an increase of nearly $16 million over 2007. Exh. 119, p. 3, l. 77. Idaho Power testified that "the five-year compounded growth rate is the most appropriate method to estimate the Company 2008 test year operations and maintenance expense based on continued growth in its service territory and the resulting financial needs balanced with the forecasting objectives identified by the Company." Tr. p. 2283.

Both the Commission Staff and Micron objected to the Company's estimated 2008 O&M expense budget. To develop a reasonable escalation amount for those accounts, Staff evaluated the data in the various accounts that comprise the O&M budget to determine which account groups showed a consistent trend. Tr. pp. 1302-1303. For example, Staff noted that the General and Administration accounts were essentially flat during the years 2004-2006, and then showed an increase of $17,597,452 in 2007 over the average. Staff attributed the significant one-year increase in 2007 to a one-time event, and testified it is unreasonable to escalate General and Administration accounts with the simple escalator the Company derived by comparing only the 2003 budget to the 2007 budget. Staff also noted that labor costs are a component in most of the O&M account groupings and that Idaho Power escalated labor costs for the test year by a separate payroll annualization and structured salary adjustment. Staff testified that it is inappropriate to escalate labor costs in the O&M budget when 2008 labor costs are directly escalated elsewhere. Tr. p. 1303.

Micron testified, in regard to the projected growth in the O&M accounts, that "no well run utility should experience prolonged O&M growth rates of this magnitude for any extended period of time, and this is doubly true when prices for items like gasoline and other commodities are in decline as they are now." Tr. p. 1687. Micron noted that the Administration and General expense category comprises more than half the forecasted O&M increase. Micron testified that "A&G expenses consist of items like office supplies, office salaries, and advertising that are subject to considerable management discretion and control, and should be one of the first places to look for savings when times get tough, as they certainly are now." Tr. pp. 1687-1689.

Both Staff and Micron noted the uneven balances in the Administration and General accounts, particularly the Purchased Services account. This expense account declined from 2004 to 2005, but increased 49%, jumping nearly $7 million from $14,216,888 to $21,192,531, from 2006 to 2007. Exh. 119, p. 3, l. 64. Similarly, the Transmission Other Expenses account declined from 2004 through 2006, but increased nearly 14% from 2006 to 2007. Exh. 119, p. 2, l. 36. The Hydro, Purchased Services expenses decreased from nearly $5.9 million in 2004 to $4.7 million in 2006, but increased more than 10% from 2006 to 2007. Exh. 119, p. 1, l. 14. The Administration and General, Materials account decreased more than 5½% from 2003 through

2007. Exh. 119, p. 3, l. 63. Staff testified to wide swings in different year-end O&M account balances from 2003 through 2007, and Exhibit 119 shows that individual balances in the O&M accounts varied greatly from year to year. Individual account balances in FERC Accounts 500-515 (O&M Steam) changed dramatically during specific years, from a decrease of 65% in one account to an increase of nearly 172% in another. Exh. 119, p. 1, ll. 3 and 4. Idaho Power nevertheless proposed an increase of 7.14% for this group of accounts.

Staff analyzed the Company's use of O&M account escalators by looking at the individual accounts "to determine if escalation of the specific accounts was reasonable," evaluating the particular account escalator "to determine if the methodology was reasonable and tested the model using data supplied by the Company," and then "determined which account groups showed a consistent trend and developed a reasonable escalation amount for those accounts." Tr. pp. 1302-1303. To determine its own escalation of the 2007 O&M accounts, Staff removed labor and Administration and General expense, and combined the Steam, Hydro and Other Power Generation accounts to evaluate expense growth. Tr. p. 1306. Staff next examined the cost elements in the combined accounts to determine whether they showed consistent growth, and discovered a consistent expense growth in the Power Generation Other Expense and Distribution Other Expense account categories. Tr. p. 1306. Staff applied a 5% growth escalator for these accounts, resulting in a projected growth of $2,876,561. *Id.* Exh. 121. Staff reduced this amount by the results of its review of the Accounting Entries expense accounts. Staff totaled the Accounting Entries expenses for the years 2003 through 2007, averaged three years of year-to-year change, and applied it to the gross escalation. The average Accounting Entries adjustment reduced Staff's escalation amount, resulting in Staff's recommendation to escalate the 2008 O&M accounts by $1,750,020. Tr. p. 1307; Exh. 122.

The Commission finds Staff's proposed escalation of the O&M accounts for the 2008 test year to be reasonable and appropriate. The Company's approach to develop an escalator for the O&M accounts, comparing only the beginning and ending values from the years 2003 and 2007, does not adequately analyze the broad range of data in these accounts. The Company's explanation that its escalator "smoothes out uneven amounts within these years" glosses over the considerable variation in account balances from year to year. For example, Idaho Power used an escalator of 2.15% for the Hydro Purchased Services account because the 2007 balance was 2.15% higher than the 2003 balance. Exh. 119, p. 1. The only increases in the account, however, occurred between 2003 and 2004 and between 2006 and 2007. The balance declined in each of the years from 2004 through 2006. The Company's methodology to increase the account in the 2008 test year does not adequately evaluate the variations in the account balances and the apparent declining rather than increasing trend.

The Company's escalation methodology also fails to address substantial increases in some accounts that occurred from 2006 and 2007, the end point for the Company's escalator. This is most apparent in the Administration and General accounts where the year-end balance increased 23.80% from 2006 to 2007, resulting in the Company's proposed escalator for this account group of 9.41%. Exh. 119, p. 3, l. 67. As Micron noted, this account group contains expenses where the Company can most exercise discretion to control costs. For the total O&M accounts, the year-end totals increased 9.65% from 2006 to 2007, bringing the Company's average escalator for these accounts to 5.82%. Exh. 119, p. 3. l. 77.

Purchase Card Expenditures

One adjustment to the 2007 base year expenses recommended by Staff did not involve a large dollar amount but generated a relatively significant amount of testimony. Idaho Power provides a OneCard Solution Purchasing Card (P-Card) to most of its employees. The cards are issued to employees to enable them to make small business purchases for the Company. In June 2007, the Company had 1,977 employees and 1,818, or 92%, had P-Cards. There were approximately 1,500 different P-Cards used to make purchases each month during 2007, and P-Card purchases for the year totaled more than $11.2 million. Tr. p. 1317. Of that amount, more than $6.5 million in P-Card purchases were charged to Operations and Maintenance, Accounts 500-935. Tr. p. 1327. After what it called "an extensive audit," Staff recommended $884,787 of the $11.2 million in P-Card purchases be removed from the 2007 expenses used as the basis to establish 2008 test year expenses. Tr. pp. 1316-1317. The effect of this adjustment is to reduce the Company's revenue requirement in the 2008 test year by $884,787.

Exhibit 125 shows the amounts Staff recommended for removal from each FERC account and the categories Staff used to identify the various P-Card purchases. The amounts Staff recommended be removed from rate recovery, by category, are (1) Gifts/Awards: $247,339; (2) Restaurant: $236,274; (3) Cell Phone charges: $306,475; (4) Bottled Water, Coffee, Newspapers: $61,729; (5) Charitable Donations: $17,606; (6) Political: $7,999; (7) Keyword Search: $7,366. Tr. p. 1321. The keyword search category came from Idaho Power's own method to remove charges that, "although the Company feels are appropriately incurred costs, the vendor name might lead an uninformed individual to come to the wrong conclusion." Tr. p. 2335. The Company used a keyword search to remove food and beverage charges from establishments that had only the word "bar" in their names. If "bar" was combined with another noun, such as "grill," the charges were not removed. Tr. p. 2335. Staff reviewed the Company's keyword search results and recommended an additional $7,366 be removed from rate recovery.

Although Staff was concerned that "the widespread use of P-Cards and the ability of an employee to take cash withdrawals to self-reimburse for expenditures prior to approval opens the door to the possibility of employee abuse," Staff did not find any evidence that employees routinely used P-Cards for personal expenses that were not reimbursed or authorized by Company policy. Tr. 1330. Rather, Staff believed the Company's policy allowed for purchases and expenses that should not be paid by the Company's ratepayers. Tr. pp. 1317-1318. For example, Staff recommended removal of approximately 38% of the total P-Card purchases related to cell phones because "it is excessive" for the Company to provide cell phones to 66% of its employees. Tr. p. 1325. Staff noted that $145,981 of the cell phone expenses were charged to Administration and General, Account 921, and that most Administration and General employees work at Company central headquarters. *Id.* Staff described the policy for meal purchases as "lax," where receipts are not required for meals costing less than $75 or for meals paid for with cash costing less than $25. Tr. p. 1328.

Idaho Power explained in rebuttal testimony that the purpose of the P-Cards "is to allow the Company to better manage high volume, low-dollar transactions and to improve cash flow management by simplifying payments, reducing paperwork, reducing processing expense, reducing multiple checks, and providing a centralized listing of all expenses." Tr. p. 2314. The Company asserted the P-Cards allow employees to make emergency field purchases and fund business-related travel expenses, and their use "saves the Company money by eliminating the need to create purchase orders and process invoice payments for small items." Tr. pp. 2314-2315.

Idaho Power was critical of Staff's audit, including the criteria Staff used for evaluating the audit evidence. Staff through discovery responses informed the Company that expenditures must be considered necessary, reasonable and prudent in providing service to customers to be recoverable in rates. Tr. p. 2321. Idaho Power described this standard as "unreasonably subjective" because Staff did not cite anything other than "personal belief" as the source to define necessary, reasonable, and prudent expenses. Tr. p. 2321.

The Company explained its oversight of various P-Card purchases to ensure employees are using them for business purposes. For example, for restaurant charges, "the Company has adequate oversight controls in place for these types of purchases in order to ensure they have a legitimate business purpose and are neither excessive nor unreasonable." Tr. p. 2324. Regarding cell phones, Idaho Power explained it "provides cell phones based solely on business necessity and has adequate controls in place." Tr. p. 2329. In addition, the Company "has commenced a complete review of all cell phone policies and procedures, which should be completed by the end of the year." To save on cell phone charges, "the Company has negotiated an umbrella contract that will cover all employees, creating a larger group and thereby providing economies of scale, which will provide significant savings to customers." Tr. p. 2329.

The Company explained its policy on Gifts and Awards and Charitable donations. "The Company provides certain benefits to employees to foster a positive working environment, good morale, and, although indirect, assist in attracting and retaining quality employees – all of which benefit customers." For example, Service Award Celebration "is for an employee's co-workers to recognize the employee for his or her time and contributions to the Company." Tr. pp. 2330-2331. For charitable donations, "the vast majority of the expenses was incurred in support of employee community involvement, which enhances employee morale and benefits the local communities that comprise Idaho Power's service territory." Tr. pp. 2333-2334.

The Commission finds Staff's relatively modest adjustment to the 2007 P-Card purchase expenses to be reasonable and appropriate. The significant total amount of P-Card purchases for 2007 by itself suggests the Company's policy for authorizing business purchases by employees may be too lenient. The explanations of Company policy regarding particular categories of purchases do not alleviate that concern. We find Staff's audit to be reasonably thorough, especially considering the limited time and resources available to Staff. On this record, the Commission approves the adjustment to reduce 2007 P-Card purchases by $884,787.

Adjustments Resolved by Agreement

Some of the Company's adjustments to the test year initially contested by Staff were resolved after rebuttal testimony was filed or at the hearing. An issue regarding the Company's depreciation expense was part of the earlier rate base discussion (accumulated depreciation is a rate base account), where the Company agreed to adjust depreciation accounts based on new depreciation rates approved by the Commission after the Application was filed in this case. Based on current depreciation rates, Staff recommended a reduction of $1,471,189 in the test year depreciation expense, and Idaho Power's witness testified that Staff "correctly adjusted the Company's filing to reflect the [new rates in] Commission Order No. 30630." Tr. p. 2313. Accordingly, the Commission approves a reduction of $1,471,189 in test year depreciation expense.

Another test year adjustment agreed to by Idaho Power was Staff's reduction in the projected payroll expense. The Company applied a 6.5% growth escalator to its payroll expense, and annualized the projected December 31, 2008 amount, resulting in a test year payroll amount of $142,943,119. Staff reviewed the actual payroll amounts for August and September 2008, and annualized the test year payroll amount based on the actual figures for those two months. Tr. p. 1264. Based on its annualization of actual payroll amounts, Staff recommended a $2,039,629 reduction in the Company's test year payroll expense. Although Idaho Power disagreed with Staff's adjustment "from a ratemaking logic perspective," the Company agreed with the adjustment in light of "the actual plateaued employment levels in 2008." Tr. p. 2528. The Company explained that it "is adjusting to the economic slowdown and has instituted a selective hiring freeze to help manage labor costs during difficult times." *Id.* Accordingly, although the Company did not agree with Staff's methodology, the Company stated Staff's payroll annualizing adjustment is reasonable "from a review of employment data after the Company filing." *Id.* Based on this record, the Commission finds Staff's adjustment to the test year payroll to be fair and reasonable, and we thus approve a reduction of $2,039,629 in the test year payroll amount.

Another adjustment Idaho Power accepted is in an Executive Deferred Compensation Account. Staff asserted that contributions to a deferred compensation account Staff characterized as a "Rabbi Trust" should be a below-the-line expense and thus paid by shareholders rather than customers. Tr. p. 1244. Staff recommended removing Company contributions to this account from the test year, resulting in a reduction of $459,524 in the Company's revenue requirement. Tr. pp. 1242-1244. In rebuttal testimony, Idaho Power conceded that Staff "is correct that the $459,524 should not have been included in the revenue requirement." Tr. p. 2339. The Commission thus approves this adjustment to the test year revenue requirement.

One test year expense adjustment recommended by Staff was withdrawn. Staff initially recommended a reduction of $15,172 in interest paid on deferred compensation for Company directors. Staff withdrew this recommendation at hearing, and thus no decision on Staff's initial objection to this expense item is necessary. Tr. pp. 1257; 1278-1280.

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

Based on the evidence presented, and including all adjustments, the Commission finds just and reasonable total system operating expenses for the 2008 test year in the amount of $701,809,051, and total operating revenues in the amount of $863,061,457. After all adjustments, we find a 2008 total system rate base amount of $2,266,517,157 to be just and reasonable. The Idaho jurisdiction rate base is $2,094,082,620; Idaho operating expenses total $657,889,811 and Idaho operating revenues total $816,477,779 for the 2008 test year.

CAPITAL STRUCTURE AND RATE OF RETURN

Capital Structure and Cost of Debt

Idaho Power presented evidence of the estimated 2008 year-end balances of its capital structure of long-term debt and common equity for use in determining a return on rate base and overall rate of return. Staff accepted the Company's figures for capital structure as consisting of 50.73% long-term debt and 49.27% common equity. Exh. 128. Accordingly, the evidence on the Company's capital structure is not disputed and the Commission finds the capital structure as stated to be appropriate for calculating the Company's overall rate of return.

Idaho Power presented evidence that its embedded cost of debt is 5.927%. Staff accepted this rate as reasonable, and no other party challenged the Company's calculation of its cost of debt. The Commission thus finds the appropriate calculation of Idaho Power's cost of debt to be 5.927%.

Cost of Common Equity Capital (Return on Equity)

The determination of an adequate return on equity is guided by U.S. Supreme Court decisions. In *Bluefield Water Works & Improvement Company v. West Virginia Public Service Commission*, 262 U.S. 679, 692, 43 S.Ct. 675, 67 L.Ed. 1176 (1923), the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of

> the country on investments in other business undertakings which are attended by corresponding risks and uncertainties . . . the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

The Idaho Supreme Court has adopted the principles established in *Bluefield Water Works*. *See In Re Mountain States Telephone and Telegraph Company*, 76 Idaho 474, 284 P.2d 681 (1955); *Hayden Pines Water Company v. IPUC*, 122 Idaho 356, 834 P.2d 873 (1992). As a result of the Court decisions, three primary standards have evolved for determining a fair and reasonable rate of return: (1) the financial integrity or credit maintenance standard; (2) the capital attraction standard; and (3) the comparable earnings standard. Tr. p. 2237.

Idaho Power presented evidence on "well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of a discounted cash flow (DCF) model and the capital asset pricing model (CAPM), as well as reference to comparable earned rates of return expected for utilities." Tr. pp. 1811-1813. The Company's expert also evaluated its return on equity by reviewing specific risks and economic requirements for the Company consistent with preservation of its financial integrity. Tr. p. 1813. Among the risks identified for Idaho Power are the Company's hydroelectric generation facilities. The Company testified that it is exposed to a level of uncertainty not faced by most utilities because approximately one-half of its total energy requirements are provided by hydroelectric facilities. Tr. p. 1822. In below average water conditions, Idaho Power is forced to rely more heavily on wholesale power markets or more costly thermal generating capacity to meet its resource needs. *Id.* Idaho Power also noted that its hydroelectric facilities are subject to administration by FERC and that relicensing of those facilities is not automatic under federal law. The relicensing process is complex, protracted, and expensive. Tr. p. 1826. The Company's witness also noted that Idaho Power anticipates construction expenditures of approximately $900 million during 2008-2010, and stated that "support of Idaho Power's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner." Tr. p. 1832.

Idaho Power concluded that its constant growth DCF results for electric utilities implied a cost of equity of 11.0%. Tr. p. 1888. The Company's CAPM model for electric utilities results indicated a return on equity of approximately 11.9%. Tr. p. 1897. A CAPM model result using risk premiums based on historical rather than anticipated rates of return resulted in a return on equity of 10.8% for the utility proxy group and 10.2% for the non-utility proxy group of companies. Tr. p. 1899. The Company's comparable earnings approach for utilities implied a rate of return on equity of 11.1%. Tr. p. 1902. The Company's expert concluded from his analysis that the cost of equity for Idaho Power should be in the 10.8% to 11.8% range. Tr. p. 1928.

Staff also used the DCF model and the comparable earnings method to evaluate the cost of equity for Idaho Power. Staff noted the comparable earnings method is premised on the idea that an investment should earn its opportunity costs. Tr. p. 2238. Staff testified that "for a utility to be competitive in the financial markets, it should be allowed to earn a return on equity equal to the average return earned by other firms of similar risks." Tr. p. 2239. Staff noted that utilities historically have lower risks compared to other industrial companies. Tr. p. 2240. Staff also testified that Idaho Power has lower competitive risks than other electric companies because of its low-cost source of hydro power, its low retail rates compared to national averages, the PCA, and the fixed cost adjustment (FCA) assuring the Company it will recover its fixed costs. Tr. p. 2241. In addition, Staff noted that proposed changes to the PCA in Case No. IPC-E-08-19 on the sharing percentage and load growth adjustment "are seen as positive by institutional investors and the investment community." Tr. p. 2241. Staff concluded that comparable earnings method implies a return on equity for Idaho Power of 9.5% to 10.5%. Tr. p. 2243. The Staff's DCF method indicated a cost of equity between 8.9% and 9.8%. Tr. p. 2245. Staff recommended an overall range of 9.5% to 10.5%. Staff also testified that any point within the range would be appropriate, but used a point estimate of 10.25% in calculating the Company's overall rate of return in the revenue requirement. Tr. p. 2247.

DOE's recommendation of 10.5% return on equity was based primarily on the DCF model using a proxy group of electric utility companies operating in the west region of the U.S. Tr. p. 2065. DOE also reviewed Idaho Power's evidence using the CAPM model, and also compared the DCF results to comparable earnings evidence. DOE testified that the 10.5% rate is higher than the DCF mid-point results, providing Idaho Power with a premium over the baseline proxy group cost of equity estimate. Tr. p. 2065. DOE had recommended a 10.25% return on equity in the Company's 2007 rate case, and "although the cost of capital data in this case have not changed substantially . . . the difficulties in financial markets (along with IPC's financial position) may warrant a moderately higher return than I recommended in last year's case." Tr. p. 2067.

In summary, the evidence established a range for an appropriate return on equity from 9.5% to 11.8%. Idaho Power's witnesses testified that the range for the cost of common equity is 10.8% to 11.8% and selected a point estimate within that range of 11.25%. Tr. pp. 1813, 2152. Staff recommended a range of 9.5% to 10.5% and selected a point estimate within that range of 10.25% – above the mid-point – in recognition of "the requirement for system capital investments to serve customers." Tr. pp. 2234, 2248. DOE recommended a range for the cost of common equity of 10.25% to 10.5% and recommended a return of 10.5%. Tr. pp. 2064-2065. Micron concluded that "a reasonable return on equity should be no more than the return of 10.25% the Commission found fair and reasonable in 2007" and asserted that no increase is justified or necessary. Tr. pp. 1703-1704.

The Commission finds that a return on equity of 10.5% for Idaho Power is fair, reasonable and appropriate. This rate takes into account the results of the analyses provided by the witnesses, and also the deteriorated economic and financial markets since the Company's last contested rate case where we approved a return of 10.25%. The determination of the appropriate cost of common equity capital primarily attempts to quantify a rate of return required by investors for that specific investment, and the evidence supports a finding that a slightly higher rate of return is required to attract investors. We are primarily concerned, however, with establishing a rate that is "reasonably sufficient to assure confidence in the financial soundness of the utility," and that is "adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." Tr. p. 2235, *quoting Bluefield Water Works, supra.* Idaho Power is facing significant capital expenditures in the next few years, and the current economic climate will affect its ability to obtain credit to build necessary facilities. The rate for return on equity we approve is an increase over its currently approved rate and should assure continued confidence in the financial soundness of the Company.

CALCULATION OF REVENUE DEFICIENCY

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

Rate Base	$2,094,082,620
Rate of Return	8.18%
Earnings Deficiency	$6,238,168
Earnings Deficiency with AFUDC	$12,715,520
Incremental Tax Multiplier	1.642
Revenue Deficiency	$20,878,884
Percent Increase Required	3.10%

COST OF SERVICE METHODOLOGY

With total Idaho jurisdictional costs determined, these costs must be allocated to Idaho Power's various customer classes. The specific allocation of costs to individual classes of customers is guided by a "cost-of-service" study.

Idaho Power presented and compared the results of three different cost-of-service studies to demonstrate that cost-of-service trends are similar. Tr. p. 157. The Company selected the 3CP/12CP model as the preferred method and "appropriate starting point for rate spread . . . and rate design." Tr. p. 158. The 3CP/12CP cost-of-service method uses allocators derived from the three summer (June, July, August) unweighted coincident peaks and all 12-month unweighted coincident peaks (3CP/12CP) to assign demand-related costs to the various customer classes. Tr. pp. 501-02. This is a change from the weighted 12 coincident peaks (WI2CP) cost-of-service study used by the Commission in Case No. IPC-E-03-13, the Company's 2003 general rate case that used cost-of-service results to allocate revenue requirement.[1] The Company asserted that the 3CP/12CP method is an improvement over the prior W12CP method and that it will more adequately assign base and intermediate generation costs to the classes. Tr. p. 561.

The 3CP/12CP method seeks to assign "production plant costs associated with serving summer peak load . . . separately from costs associated with serving base and intermediate load." Tr. p. 500. As with the prior W12CP (Base Case) method, investment in resources serving the base and intermediate loads, hydro and thermal generating resources, are

[1] Idaho Power's last two general rate case filings, Case Nos. IPC-E-05-28 and IPC-E-07-08, resulted in settlements with "no specific cost-of-service study to allocate the Idaho jurisdictional revenue requirement to customer classes." Tr. p. 1365.

classified as either demand- or energy-related based on the Idaho jurisdictional load factor, approximately 59% energy-related and 41% demand-related. Tr. pp. 1365-1367. Investment in the Company's peak-demand resources, natural gas-fired plants, are classified as 100% demand-related. Tr. p. 1367. Natural gas-fired demand-related plant costs are allocated to only the summer months using an unweighted 3CP allocator and base load demand-related plant costs are allocated to all 12 months using an unweighted 12CP allocator.

The classification of generating resources based on the jurisdictional load factor was not accepted by all parties. Micron and the Industrial Customers both accepted the 3CP/12CP study but differed with the system load factor classification approach used by the Company and supported by Staff. DOE and the Irrigators were the only parties who did not accept some form of the Company's 3CP/12CP cost-of-service methodology. DOE claimed that the study is "seriously and probably fatally flawed . . . [and] departs from Commission precedent." Tr. pp. 909-910, 914. DOE presented four different cost-of-service studies and recommended the Commission select one of the two weighted 12CP studies it submitted. Tr. p. 943.

The Irrigators believe the Commission should continue to utilize the Irrigators' variation of the longstanding weighted 12CP (Base Case) method. The Irrigators proposed the use of demand allocators that, in its view, more appropriately account for the increasing marginal cost of growth on the Idaho Power system. The Irrigators recommended the Commission adopt a cost-of-service methodology that allocates "forward looking costs . . . on the basis of <u>only the growth</u> that is anticipated from each schedule over a ten year period." Tr. at 1078. These "anticipated" costs should be based on data contained in the Company's most recent Integrated Resource Plan (IRP). Tr. at 1077.

Staff supported Idaho Power's 3CP/12CP methodology including the system load factor classification of base load production costs. Tr. pp. 1369-1370. Staff argued for the use of the 12CP allocator stating that system capacity is required in all months and thus has value in all months of the year. Tr. p. 1398. Staff made two points in its argument for system load factor classifications. First, the load factor classification approach is "the method last accepted by the Commission in the IPC-E-03-13 case." Tr. p. 1385. Second, the system load factor is a reflection of the relationship between the average demands on the system and its peak demands and is therefore "self adjusting to address changes in system generation requirements." *Id.*

DOE asserted that Idaho Power has shown "no empirical analysis to justify or support" its system load factor classification method for steam and hydro resources. Tr. p. 914. DOE argued that the Commission should allocate demand-related production costs using demand allocators based on the non-zero weighted average of six months of coincident peaks. Transmission demand-related investment should be allocated according to the unweighted, non-averaged 12 monthly coincident peak demands. In one of its recommended W12CP studies, DOE also argued that all steam and hydro production plant costs, as well as Account 555 purchased power expenses, should be classified as 57.10% demand-related and 42.90% energy-related. Tr. pp. 914-916. DOE believes that Idaho Power's hydro resources serve not only base load demand but are also used to meet the Company's summer peak demands. Tr. pp. 916-917. Accordingly, DOE recommended assigning 50% of demand-related hydro and Account 555 purchased power costs to the base load category (for allocation using 12CP allocators) and 50% to the peaking category (for allocation using 3CP allocators). Tr. pp. 917-918.

Micron also objected to the Company's classification of production plant arguing that "all plant, base load included, is built, first of all, for the peak period." Tr. p. 1753. Micron argued that the jurisdictional load factor method of classifying costs treats costs associated with base load plant "as off peak costs and they're not," and that such a classification scheme raises prices for off-peak periods and lowers them for peak periods, which is not justifiable in a summer peaking system. *Id.*

As noted by the parties, the Commission last addressed cost-of-service issues for Idaho Power in Case No. IPC-E-03-13. Since that time, Idaho Power's summer peak has grown faster than the winter peak. As a result, in this case the Commission is committed to the task of selecting a cost-of-service method that (1) properly classifies system costs; (2) accurately identifies their drivers or causes; and (3) equitably distributes them among Idaho Power's various classes of customers.

While most generally accepted cost-of-service methods contain similar principles, they may lead to disparate results and recommendations for class revenue allocation. Thus, the Commission has repeatedly emphasized that "a cost of service study is not a perfect tool for assigning system and service costs to customer classes." Order No. 29505 p. 45. We previously noted the common perception among cost-of-service experts that cost-of-service modeling is not an exact science. Order No. 25880 pp. 25-26.

We find that the system load factor approach endorsed by the Commission in Idaho Power's last general rate case reasonably depicts the Idaho Power system. Thus, we find no compelling reason to deviate from the system load factor approach to classifying production plant and purchased power costs.

Rather than using a weighted allocator based on the average demand throughout the year, Idaho Power proposed "an unweighted 3CP allocator based on the Company's three summer peak months of June, July and August." *Id.* These coincident peak demand allocators to determine demand for each customer class are derived from the "five-year median demand ratios" represented in Idaho Power's load research sampling. Tr. p. 559. The remaining demand-related investment in non-peaking base and intermediate load resources is allocated based on an unweighted 12-month demand allocator. *Id.* For the purposes of this case, we are not persuaded that weighted demand allocators produce a reasonable result. "The energy related portion of base and intermediate load production plant investment is allocated based on marginal cost weighted class energy use." *Id.*

Staff supported the Company's 3CP/12CP cost-of-service methodology, but agreed with the Industrial Customers' position that the coincident peak demand allocators should be based on the single most recent year's data (i.e., 2007) in order to account for "non-weather related factors that might cause systematic changes in coincident peaks." Tr. pp. 1394-1395.

We are persuaded by the Industrial Customers' and Staff's arguments and find that the CP demand allocators should be based on 2007 data rather than the five-year median value developed in the Case No. IPC-E-04-23 cost-of-service workshops. Using demand ratios from the most recent year available will help diminish the potential for non-weather-related factors to unduly influence class coincident peak data, and provide a more consistent and accurate representation of each class's demands on the Idaho Power system. The use of 2007 data for these demand allocators benefits the Irrigators in this case by reducing their contributions to the coincident peaks, thereby reducing the overall cost allocation to the irrigation class.

The Irrigators emphasized that "there has been strong and persistent growth in the Idaho Power system and that this growth has not occurred in the Irrigation load." Tr. p. 1052. The Irrigators attribute much of what they label "phenomenal growth on the Idaho Power system" to the increasing residential and commercial/industrial load. Tr. p. 1053. Micron responded that "there's a good deal of difference between customer growth and growth in system demand." Tr. p. 1748. "Any customer who is consuming on peak, whether they're new or whether they've grown or not, should bear that cost. . . ." *Id.*

We are not unsympathetic to the Irrigators' comments and concerns regarding the effects of system growth. There is no dispute that, over the past decade, the irrigation class's level of energy consumption has not grown nearly as much as the residential and industrial classes. Nonetheless, it is also true that the irrigation class is not entirely static – new customers continue to migrate to and from the irrigation class over time. As the Industrial Customers stated, "The irrigation class has the misfortune of having the need for power during summer on peak that is when the Company's system needs are growing the fastest." Tr. p. 2417.

We are not persuaded that the Irrigators' proposal offers an effective and reasonable method. A revised allocation method based upon the "future growth of customer classes" does not conform to any recognized embedded cost-of-service study in the NARUC Electric Utility Cost Allocation Manual. Tr. p. 1381. We find that the Irrigators' proposal seeks to establish a clear distinction between new and old customers on Idaho Power's system, a practice that has long been prohibited by the Idaho Supreme Court. *See Idaho State Homebuilders v. Washington Water Power*, 107 Idaho 415, 421, 690 P.2d 350, 356 (1984).

After reviewing the voluminous testimony and exhibits submitted by the parties dealing with the cost-of-service, the Commission finds that the 3CP/12CP methodology proposed by the Company and generally supported by Staff is the most appropriate cost-of-service study. For the purposes of this case we are not persuaded to deviate from the Company's proposed cost-of-service methodology except as previously discussed. We find that the results of the 3CP/12CP study represent a reasonable approximation of class revenue responsibility.

Revenue Allocations by Class

The Commission must now determine the actual amount of revenue to be recovered from each of Idaho Power's customer classes. The Commission views cost-of-service studies as appropriate and useful guides in its deliberations concerning the revenue spread across classes of customers, "but in the end we must, and do, consider other factors such as rate continuity, equity and proportionality." Order No. 25880 p. 27.

Idaho Power proposed a revenue allocation approach that would generally follow the results of its 3CP/12CP cost-of-service results but would also place a cap on the maximum percentage increase for any customer class at 15%. Tr. p. 534; Exh. 70.

DOE argued that "an unweighted energy cost allocation [method] should be used to ensure that higher load factor customers [e.g., DOE,] are assigned a higher percentage of the lower fuel costs associated with baseload capacity." Tr. p. 918. According to DOE, "higher load factor customers are allocated most of IPC's baseload production costs, and therefore should also be allocated most of its off-system sales revenues." Tr. pp. 911-912. DOE recommended a uniform percentage spread across all classes of customers. Tr. p. 919.

Micron suggested an overall decrease in customer rates, stating that the residential and industrial classes (including special contract customers) are currently paying rates that "exceed their cost of service" while the rates for the irrigation class "remain well below an average rate of return." Tr. p. 1741. Any reduction in rates should be spread to the residential and industrial classes. Tr. p. 1742.

The Commission finds that the recent precipitous economic decline must be considered in determining a just and reasonable approach to allocating costs. The Commission is also mindful of the significant impact that regular and persistent rate increases can have on ratepayers as a whole, specifically low-income ratepayers. Accordingly, the Commission uses its authority to fashion fair and reasonable rates that not only provide the utility a fair return and generally follow cost-of-service study results, but also avoid dramatic and sudden increases which can lead to rate shock.

Therefore, in light of our revenue requirement determination we find that the rate increase for any customer class should not exceed 6%. We also find that the revenue increases for the following classes of customers are capped at 6%: Schedule 24 (Irrigation Service); Schedule 42 (Traffic Control Lighting); and Schedule 26, 29-30 Special Contract Customers (Micron, J.R. Simplot, DOE/INL). We further find that rate decreases are not appropriate at this time.

Located below is a summary of the results of applying the 3CP/12CP cost-of-service study to recover the Commission-approved revenue requirement with no class receiving a reduction and with no rate increases greater than 6%. The resulting rate spread moves all class rates toward cost-of-service.

Tariff Description	Rate Schedule	% Increase
Residential Service	1	1.61%
Small General Service	7	0.42%
Large General Service	9	3.35%
Dusk/Dawn Lighting	15	0.00%
Large Power Service	19	5.62%
Irrigation Service	24	6.00%
Unmetered Service	40	0.00%
Municipal Street Lighting	41	0.00%
Traffic Control Lighting	42	6.00%
Special Contracts		
Micron	26	6.00%
JR Simplot	29	6.00%
DOE/INL	30	6.00%
Total		**3.10%**

RATE DESIGN

Residential

Idaho Power's Application proposed several significant changes to its current rate design for residential customers. First, the Company proposed to expand the two-tier summer month rate design for its Schedule 1 (Residential) customers by making it applicable on a year-round basis, and applying the tiered rates to the remaining residential class schedules (Schedules 4, 5) for the non-summer months. In addition, the Company's new rate design for the entire residential class would "increase the first block of energy usage [from its current level of 300 kWh] to 600 kWh for both the summer and non-summer months." Tr. p. 726. As support for its determination that 600 kWh is the appropriate cutoff for the Tier 1 block, the Company noted that the "baseline load" of its residential customers for the "shoulder months" of May and October 2007 "was 806 kWh and 838 kWh, respectively." Tr. p. 728. This level of usage includes "a customer's lighting, basic home appliances . . . as well as other household appliances. . . ." *Id.* Finally, Idaho Power determined that "the average monthly residential customer energy usage" was approximately 1,065 kWh per month in 2007 and fixed the first tier block cutoff at "approximately 60 percent of the average monthly energy usage for the Company's customers in Idaho, or 600 kWh." *Id.*

Idaho Power also proposed to increase the rate differentials between the Tier 1 and Tier 2 blocks to 20%. Tr. p. 729. The Company believes that an increase in the rate differential is warranted given the increasing disparity between the 27% higher unit energy cost in the summer months as opposed to the non-summer months. *Id.* It is also necessary in order to "send a stronger price signal to customers encouraging the efficient use of energy. . . ." *Id.*

Schedule 4 (Energy Watch) residential customers would see the "Energy charge during Energy Watch Event hours . . . increase to 22¢ per kWh." Tr. p. 731. During all other hours of the summer months the rate per kWh would be equal to Schedule 1's first tier rate and, during non-summer months, the energy charge for all hours would mirror "the same two-tier inverted block rates" proposed by the Company for its Schedule 1 customers during the non-summer months. Tr. p. 732.

For Schedule 5 (Time-of-Day) residential customers, Idaho Power would increase the monthly energy charge "equal to the overall percentage increase for the residential class, or 6.31 percent . . ." during the summer months of June through August. Tr. p. 735. During the non-summer months, the same two-tier system applicable to Schedule 1 customers year-round would likewise be applicable to Schedule 5 customers. *Id.* In addition, the Company seeks the same increase to the monthly service charge from $4 to $5 for customers taking service under Schedule 5. *Id.*

Staff generally supported the Company's effort to institute tiered rates to all of its residential customers, stating that tiered rates essentially "act as a surrogate for TOU (time-of-use) rates when TOU metering is not available and help prepare customers for the eventual implementation of TOU rates." Tr. pp. 1454-1456. Staff recommended adding a third tier to the Company's two-tiered rate proposal with a year-round structure for Schedule 1, but applying it to only the non-summer months for Schedule 4 and 5 customers. Tr. p. 1460. Staff suggested an increase in the first block to 1,000 kWh, with second block rates applying for monthly energy usage from 1,001 kWh to 2,000 kWh (up to 3,000 kWh in the winter months). Tr. pp. 1462-1464. Staff adjusted the Company's proposed rate differentials for Schedule 1, 4 and 5 residential customers, fixing the rates for energy falling within "the first block of energy approximately 12% lower than second block . . . and the [third tier] block approximately 20% above the second block for all residential classes during the non-summer period." Tr. p. 1468. Staff proposed the same rate differential for Schedule 1 customers during the summer period, but no change to the Company's summer rate differentials for Schedules 4 and 5. *Id.* Staff testified that an increase to the monthly customer charge is not warranted based upon Staff's proposed revenue requirement and cost-of-service results. Tr. p. 1460.

Staff questioned the use of the months of May and October to measure residential class baseline usage, stating that those months "serve as a poor basis for setting a base" because "much of the May and October usage cited [by the Company] includes discretionary usage. . . ." Tr. pp. 1461-1462. Staff argued that basic usage data from August and January is more appropriate for establishing tiered rates because they include usage for cooling and heating, which Staff considers to be basic needs for residential customers.

CAPAI stated that Idaho Power's proposed increase of the first-tier block from 300 kWh to 600 kWh is a step in the right direction. However, CAPAI argued that many low-income residential customers are unable to reduce their monthly energy usage enough to qualify for the reduced first-tier block.

Commission Findings on Residential Rates

After considering all of the testimony and exhibits offered by the parties, the Commission finds that a three-tiered-rate structure for all residential customers constitutes a fair, reasonable and appropriate rate design. We find that a tiered-rate scheme is an effective tool to (1) promote energy efficiency within Idaho Power's increasingly capacity-constrained system; and (2) enable cost savings. We are cognizant that Idaho Power may be concerned about returning to a three-tiered rate scheme not unlike that first advanced in 2002. We note, however, that negative feedback from residential customers regarding the previous three-tiered rate design was likely influenced by the extraordinary problems with the Power Cost Adjustment (PCA) mechanism that occurred contemporaneously with the rollout of the three-tiered rate structure. Additionally, Idaho Power and ratepayers now face an economic downturn calling for greater attention to energy conservation to mitigate peak demands on a capacity-constrained system. We are confident that the problems with the PCA mechanism have been effectively resolved in the interim and that, inasmuch as the Company is committed to educating its residential customers regarding how tiered rates can help lower their monthly bill if they reduce their energy consumption, the re-introduction of a three-tiered rate design will be better accepted by customers.

The Commission finds that there should be an increase in the amount of energy in the first block. The Company's proposal for an increase in the first block of its two-tiered rate system for Schedule 1 customers is based on shoulder months and does not include an amount for energy needs such as heating and cooling. However, Staff's recommendation for the size of the first-tier block is too generous and would not provide a proper price signal for residential customers to curb their monthly energy consumption.

The Commission finds that a three-tiered rate structure is a just and reasonable rate structure and orders Idaho Power to establish a three-tiered rate structure for Schedule 1, Schedule 4 (non-summer only) and Schedule 5 (non-summer only) residential customers, with tier block limits set at 800 kWh for the first block and 2,000 kWh for the second block. The three-tiered rate structure shall be in effect year-round for Schedule 1 customers, and maintain a distinction between summer and non-summer rates. Our decision to institute a year-round three-tiered rate design for Schedule 1 customers (and for Schedule 4 and Schedule 5 customers during the non-summer months) is based upon our finding that this rate design will (1) provide an effective price signal to high energy users during the summer peak months, and (2) create enhanced opportunities for residential customers to lower their monthly electricity bill through energy conservation.

Based on the new revenue requirement we approve in this Order, the Commission finds Idaho Power's existing residential rates to be unjust and unreasonable. The new rates we find just and reasonable for the Company's residential customers are set forth in Attachment 3 to this Order.

Irrigation (Schedule 24)

Idaho Power proposed "a load-factor pricing mechanism for in-season energy sales to irrigation customers . . . to maximize the kilowatt hour usage for each kW of billed demand." Tr. p. 864. Irrigation customers with higher load factors, i.e., greater than 45.6% (2007 class median load factor), would receive a 3% decrease in their energy rate as a reward for their increased energy efficiency. Tr. pp. 868-869. In-season secondary and transmission service customers whose energy use falls above 164 kWh per kW would qualify for a rate that is approximately 3% lower than consumers whose energy consumption falls below that threshold. Tr. p. 869.

Staff supported Idaho Power's proposal to alter its "billing structure" for irrigation customers, but with rates based on Staff's proposed revenue requirement and cost-of-service study. Tr. pp. 1476-1477. Staff stated that the Company's plan to institute "load factor pricing is a proper tool" for "encouraging energy efficiency through rate design." *Id.* However, Staff considers the proposed 3% rate differential as an "introductory level differential" and encouraged the Company to continue to work with irrigation customers and Staff "to further develop this rate design to achieve its prescribed goals." Tr. p. 1477.

Schedule 7

The Company proposed to add a block rate on the energy charge during non-summer months for Schedule 7 customers. Tr. p. 812. According to Idaho Power, the inverted block rate gives customers a price signal to encourage efficient use of energy. Tr. p. 815. The existing differential between the first and second block was maintained at the same level. Tr. p. 816.

Staff supported the Company's proposed structural changes to Schedule 7, with the exception of the increase in the customer charge. Tr. p. 1498. Staff supported the two-tiered energy charge in both the summer and non-summer months, with the first block at 300 kWh, and an increase in the differential between the charges for the two blocks during the summer months. Staff identified the tiered rates as a "reasonable surrogate for Time-of-Use rates" that send customers a message to use energy efficiently. Tr. p. 1498.

Schedule 9

The Company proposed seasonal time-of-use rates for all Schedule 9 primary and transmission service customers using the same time-of-use rate structure as Schedule 19. The Company asserted that time-of-use rates will provide customers with the economic signal that energy is more costly during both the peak hours of the day and peak months of the year. Tr. p. 826.

The Company and Staff both proposed implementing time-of-use rates without a phase-in period. Both indicated the rate differentials were small enough that customer impact would not be significant, and the cost of shadow billing during the phase-in period was not justified. The Company indicated it would implement a customer education program to explain the changes and encourage shifting usage off of peak periods.

Schedule 19 – Large Power Service

The Company proposed increases for all rate components, as well as increasing the differentials between off-peak, mid-peak and on-peak energy charges. In addition, more emphasis was placed on the demand, basic and service charge components. The Company's proposed demand charges maintain the relationships between schedules and service levels, with the exception of Schedule 19 secondary service, which were modified to maintain the proposed energy charge differentials and also to recover the residual revenue requirement. Tr. p. 839.

Off-peak energy charges were increased by 7.5% and the differential between off-peak and mid-peak for both summer and non-summer is approximately 15%. The mid-peak to on-peak differential is approximately 31%, with the overall differential between off-peak and on-peak approximately 51%.

The proposed service charge for Schedule 19 primary and transmission service would be increased to $250 per month. For secondary service, the proposed service charge would be $15 per month. The basic charge for primary service would increase to $1.00 per kW per month. The basic charge for secondary service would be $0.80 per kW per month and $0.53 per kW per month for transmission service.

Staff supported the Company's proposed increases to the differentials between the time-of-use periods but did not support an increase to the service charges. Staff's proposed rate increases reflect its lower revenue requirement. However, Staff indicated it attempted to maintain the same billing determinant spreads and relationships as those proposed by the Company. Tr. p. 1507. Based upon the lack of response by Schedule 19 customers to the existing rate differentials, Staff found increasing the differential to be appropriate. Staff found the level of increase in rate differentials to be reasonable and the resulting differentials were within the range used by other utilities with time-of-use rates. Tr. p. 1509.

On cross-examination, Staff acknowledged that the range of time-of-use differentials in use by other utilities identified by the Company ranged from 11% to 269%. The Company's proposal of a 51% differential between off- and on-peak rates was in the lower portion of that range. Staff indicated the range of reasonable differentials was relatively broad and that significantly different differentials between peak and off-peak rates could also be considered reasonable. Tr. p. 1516.

Special Contract Customers

The Company proposed keeping the existing rate structure for its three special contract customers – Micron, J.R. Simplot Company and the Department of Energy – with a uniform 15% increase in their existing rates. Staff did not present testimony directly addressing special contract customers but proposed capping the rate increases for customer classes that were significantly below the cost of service at 3.9%, based on Staff's revenue requirement.

Standby and Alternate Distribution Service

The Company proposed increases to Schedules 45 and 46 to reflect the results of the 3CP/12CP cost-of-service study.

Schedule 31 – Miscellaneous Special Contract

The Company provides customized standby service to The Amalgamated Sugar Company under the terms of a special contract. The Company proposed a change to their contractual rate to reflect the results of the 3CP/12CP cost-of-service study.

Lighting and Non-Metered Schedules

The Company proposed uniform rate increases of 2.51% in accordance with the results of the Company's cost-of-service study. Staff did not propose any changes to the structure of the lighting and non-metered service schedules. Staff proposed a smaller increase commensurate with its lower revenue requirement, 3.9%, for Schedule 42.

The Company also proposed changes to Schedule 89, Unit Avoided Cost for Cogeneration and Small Power Production. The prices in this schedule are based upon a formula previously approved by the Commission and are adjusted during the course of every Idaho Power general rate proceeding to reflect the updated values resulting from the rate proceeding.

Commission Findings on Non-Residential Rates

Pursuant to its statutory authority to establish just, reasonable and sufficient rates, the Commission finds that the rates for each of the non-residential classes shall increase in an amount commensurate with the results of the 3CP/12CP cost-of-service study, as well as the Commission-approved revenue requirement established herein.

Specifically, the Commission finds the inclusion of a "load factor pricing mechanism" for Schedule 24; modifications to the rate differentials for Schedule 19; introduction of a two-tiered rate structure, with the first block at 300 kWh, for Schedule 7; and the introduction of seasonal time-of-use rates for Schedule 9 primary and transmission service customers proposed by the Company to be just and reasonable alterations to Idaho Power's current rate structure. The Commission orders that these modifications be implemented, and that all other rate components be modified in a manner consistent with the Commission-approved revenue requirement and as directed in this Order. The rates we find just and reasonable are provided in Attachments 1 and 2 to this Order.

CONSUMER ISSUES

Staff and CAPAI presented the following issues in their testimony for the Commission's consideration:

1. Whether the Company has adequately explored alternatives to its current system of charging its customers a "convenience fee" in order to pay their bills online?

2. Whether Idaho Power should be ordered to confer with Staff and other parties regarding the development of effective strategies on limiting the number of customer defaults?

3. Whether Idaho Power should be ordered to submit a monthly "arrearages" report?

The Commission notes that it opened a generic docket to explore energy affordability issues, Case No. GNR-E-08-01. Idaho Power, CAPAI and Staff have submitted official comments and actively participated in the Energy Affordability Workshops associated with that case. Therefore, the Commission finds that the aforementioned issues are more properly addressed in that forum and herein defers any judgment regarding those matters to the forthcoming Commission Order in Case No. GNR-E-08-01.

Low-Income Home Energy Assistance and Project Share

CAPAI petitioned the Commission for "an increase in the funding to Idaho Power's low-income weatherization program." Tr. p. 1630. CAPAI proposes a three-year phase-in of the increased program funding in the amounts of $1.5 million in 2010, $1.75 million in 2011 and $2.05 million in 2012. Tr. p. 1640. According to CAPAI, the Low-Income Weatherization Program allows the local Community Action Partnership (CAP) agencies to assist low-income homeowners to not only lower their monthly electric bills in the short term but also offer them a "long term solution by continuing to reduce electric costs in the future." Tr. p. 1637.

Staff offered no specific opinion of CAPAI's request but noted that the Idaho Power funded weatherization program, known as Weatherization Assistance for Qualified Customers Program or WAQC, is currently being offered to homeowners "whose income is 150% of poverty or less;" and that the program was responsible for weatherizing 397 dwellings in 2007 at a total cost of $1,124,581, excluding administration costs. Tr. p. 1547. Additionally, Staff mentioned that Idaho Power has recently instituted a Home Weatherization Pilot Program that would provide weatherization services to residential customers whose annual income is between 161% and 250% of the poverty level and use electricity to heat [their] home." Tr. p. 1548.

The Commission finds that Idaho Power is actively involved in funding program efforts to assist low-income ratepayers in weatherizing their homes. Thus, we find it unnecessary to issue a ruling on CAPAI's request for increased funding. At this time, we simply encourage the Company to continue its efforts and work with all deliberate speed, in conjunction with the various Community Action agencies, to fully implement the WAQC and Home Weatherization Pilot Program.

Energy Efficiency Education

CAPAI also proposed that Idaho Power expand its Energy Efficiency Education Program to include more homes. Tr. p. 1640. "Currently only those homes qualifying for weatherization assistance . . . receives this education" and "only 10% of homes receiving LIHEAP receive this education." *Id.* CAPAI requests funding to provide "low income energy conservation education . . . in the amount of $25,000.00 annually for each [CAP] agency in its service territory, for a total of $125,000.00 annually." Tr. pp. 1640-1641. Staff offered tacit support for this request by recommending that the Commission "encourage the Company to look for new and creative ways to increase energy efficiency and provide assistance to customers, particularly those customers who are economically disadvantaged." Tr. p. 1532.

The Commission finds that CAPAI's request for increased funding for energy efficiency education targeted specifically to low-income customers is reasonable. We recently approved a similar request made by CAPAI and agreed to by the parties in the stipulated Settlement Agreement reached by the parties in Avista Corporation's last general rate case. *See* Order No. 30647 p. 9. Thus, the Commission directs Idaho Power to fund each of the Community Action Partnership (CAP) agencies located throughout its service territory in the amount of $25,000 annually – for a total amount of $125,000 annually.

INTERVENOR FUNDING

Applications for intervenor funding were timely filed by the Idaho Irrigation Pumpers Association, Inc. (Irrigators) and Community Action Partnership Association of Idaho (CAPAI). *Idaho Code* § 61-617A authorizes an intervenor cost award not to exceed a total of $40,000 for all intervening parties combined. The Irrigators requested recovery of fees and expenses totaling $76,483.70. CAPAI requested intervenor funding to recover $9,183 in fees and costs.

Individual intervenor funding 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.

Both 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 CAPAI and the Irrigators, the advocacy of each influenced the ultimate decisions made by the Commission. 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 CAPAI, who participated in the case to represent low-income general public customers 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. Both CAPAI and the Irrigators fully participated in the case by presenting prefiled testimony, attending the hearings, and cross-examining witnesses. CAPAI is a public-interest entity with modest financial resources and would probably not be able to participate without intervenor funding. CAPAI brings a perspective to the hearing that may otherwise be overlooked or underrepresented, and we appreciate CAPAI's frugal approach to its funding requests. The Irrigators represent agricultural business interests. It is a non-profit association that depends on voluntary dues from its members, as well as intervenor funding awards, to meet its budget.

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 CAPAI to the extent authorized by statute. The Commission approves intervenor funding in the amount of $9,183 to CAPAI and $30,817 to the Irrigators. Section 61-617A requires that intervenor funding "be chargeable to the class of customers represented by the qualifying intervenors." Accordingly, CAPAI's intervenor funding award is to be recovered from Schedule 1 customers, and the Irrigators' award shall be recovered from Schedule 24 customers. We believe this allocation best satisfies the considerations set forth in *Idaho Code* § 61-617A.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over Idaho Power Company, an electric utility, and the issues presented in this case, by the authority granted it under Title 61 of the Idaho Code and pursuant to the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq.*

ORDER

IT IS HEREBY ORDERED that Idaho Power Company file tariffs in conformance with this Order to be effective on February 1, 2009, for service rendered on and after that date.

IT IS FURTHER ORDERED that Idaho Power Company shall file a status report with the Commission by November 15, 2009, regarding relicensing of the Hells Canyon facilities, including the accumulation of AFUDC. If the relicensing project is not completed, the report should explain the Company's efforts to complete the relicensing, and provide updated evidence to support continued collection of AFUDC in rates beyond December 31, 2009.

IT IS FURTHER ORDERED that Idaho Power provide funds to each of the Community Action Partnership agencies within its service territory in the amount of $25,000 annually, for a total amount of $125,000 annually, for energy efficiency education programs.

IT IS FURTHER ORDERED that the Joint Motion filed by Staff and the Company to defer a prudency determination on energy efficiency rider expenditures is granted. The Commission grants the Joint Motion and defers a decision on the prudency of the demand-side management expenditures.

IT IS FURTHER ORDERED that intervenor funding is awarded to CAPAI in the amount of $9,183 and to the Irrigators in the amount of $30,817. CAPAI's intervenor funding shall be recovered from Schedule 1 customers, and the Irrigators' intervenor funding shall be recovered from Schedule 24 customers.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 29th day of January 2009.

MACK A. REDFORD, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

JIM D. KEMPTON, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/O:IPC-E-08-10_ws2

Idaho Power Company
Calculation of Rates Per Final Order
State of Idaho
Normalized 12-Months Ending December 31, 2008
General Rate Case No. IPC-E-08-10

Line No	Tariff Description	(1) Rate Sch. No.	(2) 2008 Avg. Number of Customers	(3) 2008 Sales Normalized (kWh)	(4) 06/01/08 Base Revenue(*)	(5) Revenue Adjustments	(6) Proposed Effective Revenue	(7) Avg. Mills Per KWH	(8) Percent Change
	Uniform Tariff Rates:								
1	Residential Service	1	391,376	5,062,831,147	$317,817,043	$5,102,195	$322,919,238	63.78	1.61%
2	Residential Service Energy Watch	4	62	965,866	59,223	2,258	61,481	63.65	3.81%
3	Residential Service Time-of-Day	5	87	1,289,934	80,195	2,048	82,243	63.76	2.55%
4	Small General Service	7	31,171	190,586,226	15,161,378	63,343	15,224,721	79.88	0.42%
5	Large General Service	9	26,848	3,601,578,430	157,444,264	5,277,260	162,721,524	45.18	3.35%
6	Dusk to Dawn Lighting	15	-	5,957,094	1,004,508	0	1,004,508	168.62	0.00%
7	Large Power Service	19	111	2,123,608,415	70,271,106	3,948,867	74,219,973	34.95	5.62%
8	Agricultural Irrigation Service	24	15,484	1,551,322,661	77,045,574	4,622,682	81,668,256	52.64	6.00%
9	Unmetered General Service	39	0	0	0	0	0	0.00	0.00%
10	Unmetered General Service	40	1,855	16,739,169	966,491	0	966,491	57.74	0.00%
11	Street Lighting	41	140	22,084,297	2,314,259	0	2,314,259	104.79	0.00%
12	Traffic Control Lighting	42	220	4,207,305	155,203	9,311	164,514	39.10	6.00%
13	*Total Uniform Tariffs*		467,354	12,581,170,544	$642,319,244	$19,027,964	$661,347,208	52.57	2.96%
	Special Contracts:								
14	Micron	26	1	703,404,640	$20,003,958	$1,200,280	$21,204,238	30.15	6.00%
15	J R Simplot	29	1	189,569,677	5,018,159	301,122	5,319,281	28.06	6.00%
16	DOE	30	1	215,000,001	5,828,175	349,760	6,177,935	28.73	6.00%
17	*Total Special Contracts*		3	1,107,974,318	$30,850,292	$1,851,162	$32,701,454	29.51	6.00%
18	***Total Idaho Retail Sales***		467,357	13,689,144,862	$673,169,536	$20,879,126	$694,048,662	50.70	3.10%

(*) As Filed in Case No. IPC-E-08-01

ATTACHMENT 1
ORDER NO. 30722
CASE NO. IPC-E-08-10

Idaho Power Company
Calculation of Rates Per Final Order
State of Idaho
Normalized 12-Months Ending December 31, 2008
General Rate Case No. IPC-E-08-10

Line No	Tariff Description	(1) Rate Sch. No.	(2) 2008 Avg. Number of Customers	(3) 2008 Sales Normalized (kWh)	(4) 6/1/08 Base Revenue	(5) Revenue Adjustments	(6) Proposed Effective Revenue	(7) Avg. Mills Per KWH	(8) Percent Change
	Uniform Tariff Rates:								
1	Large General Secondary	9S	26,702	3,191,280,136	$141,909,176	$4,756,535	$146,665,711	45.96	3.35%
2	Large General Primary	9P	144	407,850,707	15,440,635	517,562	15,958,197	39.13	3.35%
3	Large General Transmission	9T	2	2,447,587	94,453	3,163	97,616	39.88	3.35%
4	Total Schedule 9		26,848	3,601,578,430	$157,444,264	$5,277,260	$162,721,524	45.18	3.35%
5	Large Power Secondary	19S	1	8,483,212	$317,115	$17,819	$334,934	39.48	5.62%
6	Large Power Primary	19P	107	2,043,010,429	67,772,673	3,808,481	71,581,154	35.04	5.62%
7	Large Power Transmission	19T	3	72,114,774	2,181,318	122,567	2,303,885	31.95	5.62%
8	Total Schedule 19		111	2,123,608,415	$70,271,106	$3,948,867	$74,219,973	34.95	5.62%
9	Irrigation Secondary	24S	15,484	1,551,322,661	$77,045,574	$4,622,682	$81,668,256	52.64	6.00%
10	Irrigation Transmission	24T	0	0	0	0	0	0.00	0.00%
11	Total Schedule 24		15,484	1,551,322,661	$77,045,574	$4,622,682	$81,668,256	52.64	6.00%

New Residential Rate Design Per Final Order
General Rate Case No. IPC-E-08-10

	Block	Rate per kWh	Rate Differential
Schedule 1 (Summer)			
Tier 1	0-800 kWh	*5.7785¢*	
Tier 2	801-2000 kWh	*6.586¢*	12% > Tier 1
Tier 3	>2000 kWh	*8. 168¢*	24% > Tier 2
Schedule 4 (Summer)			
	Energy Watch Hours	*20.000¢*	223% higher
	Other Summer	*6.1991¢*	
Schedule 5 (Summer)			
	On-Peak	*8.9967¢*	36% > Mid-P
	Mid-Peak	*6.6152¢*	-
	Off-Peak	*4.9614¢*	25% < Mid-P
All Residential Non-Summer			
Tier 1	0-800 kWh	*5.5792¢*	
Tier 2	801-2000 kWh	*6.1991¢*	11% > Tier 1
Tier 3	>2000 kWh	*7.1290¢*	15% > Tier 2