Electrical Power in Idaho

Idaho residents consistently enjoy some of the least expensive electric service in the nation, according to surveys conducted by the National Association of Regulatory Utility Commissioners (NARUC), the Edison Electric Institute and the Energy Information Administration of the U.S. Department of Energy.

Idaho Power Company

2008 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
389,117 Residential Customers/$0.0671
75,605 Commercial Customers/$0.0521
114 Industrial Customers/$0.0365

Avista Utilities

2008 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
103,795 Residential Customers/$0.0723
16,356 Commercial Customers/$0.0705
482 Industrial Customers/$0.0455

2008Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)

PacifiCorp/Rocky Mountain Power

55,818 Residential Customers/$0.0804
7,717 Commercial Customer/$0.0674
5,487 Industrial Customer/$0.0495

Summary of major electric rate cases

Idaho Power Company had two major rate adjustments on Feb. 1 and June 1 and, at year's end, the Commission was considering a settlement that would place a moratorium on future base rate cases through January 2012.

The rate case completed in late January (IPC-E-08-10) resulted in an average 4 percent increase after an appeal. Most significant about this case was the implementation of tiered rates.

The larger rate adjustment for customers, however, came later on June 1 with the yearly Power Cost Adjustment, a 10.2 percent increase. Three other adjustments, including the Fixed Cost Adjustment (FCA), an increase to the Energy Efficiency Rider and the first installment of automated meters, were implemented on the same date, resulting in an overall increase of about 15.5 percent.

A summary of these major rate change cases follows.

Idaho Power gets 3.1 percent increase; 1.6 percent for residential customers

Case No. IPC-E-08-10, Order No. 30722
January 30, 2009

Rates for Idaho Power Company customers will increased by an average 3.1 percent effective Feb. 1. Rates for residential customers increased an average 1.6 percent.

In July 2008, Idaho Power asked for an overall average 9.89 percent increase, 6.31 percent increase for residential customers. The utility asked to increase annual revenue requirement by $66.6 million and was granted $20.87 million. The commission approved an 8.18 percent rate of return and 10.5 percent return on common equity. The company requested 8.55 percent and 11.25 percent respectively.

The order established a year-round, three-tiered rate structure for residential customers to promote energy efficiency and provide cost-saving opportunities. The new non-summer residential rate of 5.58 cents per kilowatt-hour for the first 800 kWh of monthly use (the first tier) was actually less than the previous non-summer rate of 5.78 cents per kWh.

Idaho Power proposed a two-tiered rate under which customers would pay a rate 20 percent higher than the first tier once their monthly consumption exceeded 600 kWh. Instead, the commission adopted a three-tiered rate of 5.58 cents per kWh for non-summer use up to 800 kWh; 6.2 cents per kWh for use between 801 and 2000 kWh and 7.13 cents for use of 2,001 kWh or more. During the summer months, the first tier is 5.78 cents, the second tier is 6.59 cents and the third tier, 8.17 cents. Idaho Power's former summer rate was 5.78 cents on the first 300 kWh and 6.51 cents for use beyond that.

The rates approved for the major rate classes (with the company's original proposal in parenthesis) are as follows:

Residential – 1.61 percent *(6.3 percent)*
Small commercial – 0.42 percent *(10.6 percent)*
Large commercial – 3.35 percent *(15 percent)*
Industrial – 5.62 percent *(15 percent)*
Irrigation – 6 percent *(15 percent)*

In adopting a significantly smaller revenue requirement than the utility requested, the commission noted the deteriorating economic conditions since Idaho Power made its application to the commission last July. "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 based on 2007 customer growth" and then extrapolated by the company into 2008, the commission said.

The commission said it expected Idaho Power to continue to demonstrate ongoing efforts to reduce operating costs and increase efficiencies. Because of the tough economic climate, the commission said all utilities' fiscal responsibility will be "reviewed extensively and continually."

The commission disallowed some of Idaho Power's proposed expenses. The utility proposed to include in its revenue requirement an increase of nearly $16 million in operation and maintenance expenses over 2007 levels based on anticipated growth in its service territory. The commission allowed $2.87 million, noting that this is an area where Idaho Power has the most discretion to control costs. The commission also deducted $11.2 million from the company's proposed $91.4 million in net power supply costs (fuel to operate plants, power purchases from the wholesale market and other utilities and purchases from in-state small-power facilities).

The commission disallowed the following amounts in these other categories: employee incentive compensation accounts ($3.2 million), legal services ($192,300) and employee purchase card expenses ($885,000). Idaho Power agreed with commission staff's findings to reduce $1.4 million in depreciation expense and $2 million in payroll expense due to a lack of increase in employees during 2008. The company said it has responded to the economic slowdown by instituting a selective hiring freeze. The commission also is requiring Idaho Power to reimburse customers $3.26 million over five years. That is the amount credited to Idaho Power by federal agencies after it successfully challenged the amount of fees it had to pay the Federal Energy Regulatory Commission and other agencies during 1999-2006.

In a departure from past practice, the commission allowed the utility to include a greater proportion of projected costs in rates to more closely align rates with the company's expenses, thereby improving its credit rating and borrowing capacity. Typically, only actual, historical costs are included in rates. But because of the time it takes to process a rate case (about six months), the company often incurs expense that it cannot recover until months after new plant is in use. The commission allowed Idaho Power to include major plant addition in excess of $2 million that was to be completed by Dec. 31, 2008 and allowed it to include an escalation in some expense accounts where a specific trend could be identified. However, the commission did not allow as much in forecasted expense as Idaho Power wanted.

The company's ongoing construction needs also prompted the commission to include in rates an allowance for funds used during construction (AFUDC) totaling $6.8 million related to the Hells Canyon relicensing projects. Typically, AFUDC is not included in rates until a project is in use and benefitting customers. In 2006, the Idaho Legislature amended a 1984 statute that prohibited the commission from including those costs in rates except in extreme emergencies. The 2006 amendment said construction work in progress and plant held for future use can be included in rates if the commission makes an explicit finding that including those costs is in the public interest.

Including the Hells Canyon costs is in the public interest, the commission said, because paying down some relicensing accounts now will mean smaller rate increases in the future because all prudently incurred relicensing costs will have to be included in future rates. Further, the commission said, "Idaho Power's cash flow will improve, which will help maintain its credit strength to access funds for ongoing construction projects." The commission said the relicensing effort, which is required by the Federal Energy Regulatory Commission and has cost $95.6 million through 2007, is unlike a typical construction project because it has been under way for nearly 10 years with no certain completion date. Further, Idaho Power is able to use the Hells Canyon complex hydroelectric projects during relicensing, thus benefiting customers.

The commission also approved a request by the Community Action Partnership Association of Idaho (CAPAI) to require Idaho Power to provide $25,000 annually to each of the state's five community-action regions for energy-efficiency education projects. The commission declined a request by CAPAI that Idaho Power increase funding for low-income weatherization. The commission said the utility is already actively involved in funding low-income weatherization projects.

Idaho Power gets another 1 percent on reconsideration

Case No. IPC-E-08-10, Order No. 30754
March 20, 2009

The Idaho Public Utilities Commission granted portions and denied portions of Idaho Power Company's petition for reconsideration of a recently concluded rate case.

On Jan. 30, the commission issued an order granting Idaho Power an average 3.1 percent rate increase. Idaho Power appealed some issues to the commission and the commission granted some of the company's request. The result is a 1 percent increase in the overall rate. The average increase for all customer classes is now 4 percent. For residential customers, the increase goes from 1.6 percent to 3 percent. Counting the changes made in reconsideration, the commission approved $27.6 million in annual new revenue for the company, out of a total request of $66.6 million.

The commission approved the following changes to its Jan. 30 order:

- Nearly $6 million out of a total $141 million in annual payroll expense was not included in the final revenue requirement and should have been.
- An error in the calculation of Operations and Maintenance Expense added another $546,221 to Idaho Power's revenue requirement.

The commission denied Idaho Power's petition in these areas:

- During 1999-2006, the Federal Energy Regulatory Commission over-charged Idaho Power about $3.27 million in regulatory fees. The company disputed the commission's order that the over-billed amount be refunded to ratepayers, maintaining a refund to customers violates the legal prohibition against "retroactive ratemaking." The commission denied Idaho Power's request and ordered that customers be credited $653,202 in each of the next five years.
- Idaho Power asked the commission to reconsider its decision to deny about $885,000 in revenue for Idaho Power needed to cover employee purchase-card expenses. The commission, denied the request, saying the company was not able to demonstrate why these kinds of employee purchases are a benefit to customers and, therefore, should not be included in rates.

The commission also denied the Department of Energy's petition to reconsider the cost-of-service model used to determine which costs should be assigned to each customer class. DOE participated in the case to represent the Idaho National Laboratory in eastern Idaho, one of Idaho Power's largest customers.

Commission approves four rate increases

May 29, 2009

The Idaho Public Utilities Commission approved four rate adjustments , which, for most Idaho Power Co. customers, will increase overall rates by an average 15.5 percent. The largest of these is the annual **Power Cost Adjustment**, which is a 10.2 percent increase over the current overall rate.

The other three adjustments include an increase in the **Energy Efficiency Rider** (2.25 percent), money for the installation of **automated meters** (1.8 percent) and the annual **Fixed Cost Adjustment** (1.3 percent).

The commission is reluctant to approve any rate increases beyond what is necessary, especially during these economic times. However, the commission is convinced the reduced energy use that will result from the Energy Efficiency Rider, the Fixed Cost Adjustment and the installation of automated meters will keep customer rates lower than they otherwise would have been in future years. "… The commission must also keep an eye toward the future and maintain a proactive approach that will best serve long-term ratepayer interests."

Power Cost Adjustment
IPC-E-09-11, Order No. 30828

Every year on June 1, customers receive either a one-year surcharge or credit to rates, depending on steamflows and market conditions from the previous year and a forecast of the following year's conditions. The increase in the PCA is from 0.7864 cents per kWh to 1.4 cents per kWh.

Idaho Power initially requested an average 11.4 percent increase but revised its request to 10.2 percent after a wet spring. Despite a wetter than normal spring, the overall precipitation for the season is only 81 percent of normal.

The power cost surcharge covers expenses, not already included in base rates, which Idaho Power incurs to provide energy to its customers. These can include expenses related to Idaho Power buying power from the wholesale market or firing up its own natural gas peaker plants during times of high demand. **None of the money collected in the surcharge goes to increase company earnings, but can be used only to pay off power supply and related expenses.** "We remind customers frustrated by the rate increase that the PCA does not influence Idaho Power's profits," the commission said.

This year is the third-largest PCA in its 16-year history. The methodology used last year to forecast this year's power supply expenses "grossly underestimated" the company's actual expenses, the commission said. A newer methodology used this year forecasts higher costs that should be closer to the actual costs the company will incur in the next year. Because of that, the commission anticipates a decline in the PCA next year even if projected stream flows are below normal.

Because the PCA is high, both commission staff and the Industrial Customers of Idaho Power requested that some expenses be deferred or spread out over the next three years. Commission staff proposed allowing only half of the forecasted amount this year and including the remainder next year. That would have reduced the increase from 10.2 percent to about 6.1 percent. The Industrial Customers proposed the expenses be recovered over the next three years in equal annual installments.

The commission, expressing concern about unknown future water and market conditions, said it was "reluctant to create a situation where customers are required to continue paying costs from this year on top of whatever increases may be required in future years." Further, the commission said, collecting the full amount in one year assures the financial community that the company is able to recover reasonably incurred power supply costs.

<u>Energy Efficiency Rider</u>
<u>IPC-E-09-05, Order No. 30814</u>

The money raised from the 2.5 percent Energy Efficiency Rider is used to fund up to 20 programs that reduce customer demand on Idaho Power's electric system. That demand reduction reduces the amount of electricity Idaho Power has to buy or generate, saving customers money in the long-run.

On June 1, the rider increased from 2.5 percent to 4.75 percent of customer bills. The increase in the rider is primary due to a new commercial demand response program and a greater than anticipated participation in the Irrigation Peak Rewards Program, which will be capable of reducing Idaho Power's peak loads in the summer by 200 megawatts. **<u>None of the funding from the rider can increase earnings for Idaho Power, but can be used only to fund energy efficiency and conservation programs.</u>**

"Rate increases are never popular and are especially unwelcome in difficult economic times," the commission said. "However, the information provided shows that energy efficiency programs have been effective in creating more efficient use of electricity by customers, and in reducing the peak demand on Idaho Power's system. These results mean that higher rates to support construction of new generating facilities have been delayed or avoided altogether."

The rider was created in 2002, after the Western energy crisis of 2000-01. At that time, the commission directed Idaho Power to develop comprehensive demand-side management (DSM) and energy efficiency programs to help customers reduce bills and lessen Idaho Power's dependency on the volatile wholesale market for electric supply.

Energy efficiency programs in 2008 resulted in 107,484 megawatt-hours of energy savings, a 72 percent increase over the 2007 total of 62,544 MWh. DSM programs that reduce demand on Idaho Power's system provided 58 megawatts of demand reduction in 2008 compared to 48 MW in 2007. (One megawatt is one million watts, enough electricity to power about 650 average homes and light 10,000 100-watt light bulbs.)

"By encouraging energy efficiency programs through relatively modest increases in the rider, the commission is delaying, or avoiding altogether, larger rate increases necessitated by Idaho Power's investment in generation resources," the commission said.

The Northwest Energy Coalition and the Idaho Irrigation Pumpers Association filed comments in support of the rider, although the coalition said the amount of the rider is "insufficient to capture all the cost-effective energy savings potential in Idaho Power's service territory and to operate robust demand-response programs to reduce peak generation resource needs." The coalition noted that "using electricity more efficiently is the quickest and least-cost approach to meeting customers' power needs" because it reduces customer bills and reduces loads during peak periods when Idaho Power's system is most stressed.

<u>Fixed-Cost Adjustment</u>
<u>IPC-E-09-06, Order No. 30827</u>

The Fixed Cost Adjustment was implemented in 2007, the first year of a three-year pilot program. The adjustment allows Idaho Power to recover fixed costs it loses when conservation programs result in lower power sales. Without a mechanism like the FCA, there is a financial disincentive for utilities to promote energy efficiency and conservation programs because they lose money when those programs are successful. The FCA allows Idaho Power to recover its already established fixed costs through a surcharge when it under-collects fixed costs because of reduced electrical use. Conversely, if the company over-collects fixed costs, customers receive a credit instead of a surcharge, as they did last year.

Idaho Power under-collected $1.3 million in fixed costs from the residential class and $1.4 million from the small-commercial class, necessitating an increase of about 0.0529 cents per kWh, or a 0.82 percent overall increase. However, because last year's FCA was a credit, the net change is 0.0986 cents per kWh or a 1.3 percent net increase.

Advanced Metering Infrastructure
IPC-E-09-07, Order No. 30829

Responding to a directive from the commission, Idaho Power has begun a three-year process to replace its existing meters with advanced metering infrastructure (AMI) that will eventually allow customers to monitor electric prices and adjust their use to take advantage of lower price-periods.

Idaho Power estimates the project will cost $71 million over its three year phase-in process. In this application, Idaho Power sought the first installment, or $11.2 million for investments made between June 1, 2009, and May 31, 2010, which would have resulted in a 2.22 percent increase.

However, the commission adopted its staff's recommendation to include only costs through 2009, as more representative of the company's actual investment. The resulting increase is 1.8 percent. "We are confident that such an approach will provide the necessary protection to ratepayers and ensure that the company is able to maintain adequate cash flow and access to sufficient capital to maintain a secure financial footing in the midst of the current economic downturn," the commission said.

The Snake River Alliance filed comments supporting the company's application, but acknowledged that the meters' benefits won't be realized immediately. However, "eventual benefits will lead to real energy savings that will benefit all customers … through reduced energy bills and reduced need for additional investments in generation and transmission."

The commission is urging Idaho Power to "move forward with all deliberate speed" with installation beginning this year in the Boise area, then in 2010 in the Canyon and Payette regions and, finally, in 2011 in the Magic Valley, Pocatello and Salmon areas. Idaho Power is pursing federal stimulus dollars to help fund the project, which could eventually reduce ratepayer costs.

Commission taking comments on rate moratorium

Case No. IPC-E-09-30, Order No. 30960
December 10, 2009

At year's end, the Commission was still considering an application by Idaho Power Company proposing adoption of a settlement that would place a moratorium on general rate case increases until January 2012 and give the company a better opportunity to earn its allowed rate of return.

The settlement, agreed to by Idaho Power and a number of customer groups, would allow Idaho Power to use some of the reduction in the Power Cost Adjustment (PCA) surcharge that customers are expected to get next June. The PCA is a one-year surcharge or a one-year credit depending on the previous year's water levels and market conditions. The PCA was a significant increase to customers in 2007 and 2008. The last year customers got a PCA credit was in 2006.

The agreement would allow the company to convert up to $25 million of the first $50 million of anticipated PCA rate reduction to base rates. Customers are expected to benefit next June with a signification reduction, now estimated to be about $160 million.

The agreement also allows the company to accelerate the use of the customer share of tax credits the company receives on its capital investments. Typically, the customer portion of the tax benefit is credited over the lifetime of the investment. Under the proposed settlement, Idaho Power would use the out years of the investment credit to buttress its earnings rather than asking for a general rate increase. The agreement limits the amount of the investment tax credit that can be accelerated to $45 million over three years.

The accelerated tax credit would help the company earn up to a 9.5 percent return on equity over the years of the agreement. Without it, the company claims customer rates would increase significantly to bring the company up to its allowed return on equity (ROE) of 10.5 percent. Increasing the ROE adds millions to a general rate case request and is one of the more significant rate case expenses.

Idaho Power proposes to share earnings with customers through rate reductions if the company's ROE is higher than 10.5 percent. When the ROE is less than 9.5 percent, the company would be able to amortize the investment tax credits, but not to exceed $45 million. Idaho Power has not able to earn its authorized rate of return throughout this decade in either Idaho or Oregon jurisdictions.

The moratorium would affect only changes in base rates. It does not include increases or decreases to the annual PCA, the annual Fixed Cost Adjustment or energy efficiency riders.

Parties to the settlement include Idaho Power, the Industrial Customers of Idaho Power, the Community Action Partnership Association of Idaho, the Idaho Irrigation Pumpers Association, Micron Technology Inc., the U.S. Department of Energy and the Kroger Company. Commission staff is also a party to the agreement. The staff operates independently of the three commissioners who will decide the case.

Avista Utilities, which serves 120,000 electric customers and 74,000 gas customers in north Idaho, filed a joint electric and natural gas rate increase in January. In July, the Commission approved a settlement that increased base rates by 5.7 percent, but because of a 4.2 percent reduction in the company's annual Power Cost Adjustment, the net increase was 1.5 percent. On the gas side, the base rate increase was 2.1 percent, but customers did not pay more this year because of a reduction in the Purchased Gas Cost Adjustment.

Idaho commission adopts Avista rate case settlement

Case No. AVU-E-09-01 and AVU-G-09-01, Order No. 30856
July 17, 2009

Avista Utilities residential electric and gas customers will pay just slightly more than 1 percent more per month – about $1 – on each of their electric and gas bills as the result of four rate adjustments effective Aug. 1.

The Idaho Public Utilities Commission announced two adjustments July 17 – a base rate increase and an electric and gas supply decrease – and later that month announced an increase in the company's energy efficiency rider later. The fourth component, the resumption of the Residential Exchange Credit from the Bonneville Power Administration, resulted in a rate decrease.

The July order adopted a settlement among various parties to the joint electric and gas rate case filed by Avista in January. The result of the rate case is an average 1.5 percent increase for electric customers (1.2 percent for residential customers) and no increase for gas customers. However, when including the increase in the energy efficiency rider announced later, the net result for residential gas customers is about a 1.2 percent increase.

The settlement increased Avista Utilities' annual electric revenue by $12.5 million and gas revenue by $1.93 million. Avista originally sought a $31.2 million increase in annual electric revenue and a $2.7 million gas revenue increase.

Noting that the disputes among the parties to the rate case were "numerous and significant," the commission congratulated the parties for "their diligent work on the settlement and their ability to resolve all the issues in this case." The commission said the settlement represents "a significant reduction in the requested revenue increase, about 60 percent less than originally requested."

The permanent base electric rate increases by 5.7 percent, but because of a 4.2 percent reduction in the company's annual Power Cost Adjustment (PCA), the net increase to all electric customer classes is 1.5 percent (1.22 percent for the residential class). Avista originally sought a 12.8 percent base electric increase that would have netted 7.8 percent with the PCA reduction. On the gas side, the permanent rate increase is 2.1 percent, but because of a decrease in the annual Purchased Gas Cost Adjustment (PGA) there was no net increase in gas rates for most customers.

For a residential electric customer who uses about 1,000 kilowatt-hours per month, the net impact of all four adjustments was an increase of 98 cents, from $79.92 to $80.90, according to the company's calculations.

For a residential gas customer who uses 65 therms per month, the net impact of all four adjustments is about 91 cents a month. An average monthly bill increased from $72.97 to $73.88, according to Avista's calculations.

The commission conducted hearings and workshops in northern Idaho and received about 200 written comments. Many of those comments addressed the issue of company salaries. The settlement adopts the commission staff proposal "to reduce wages for executive and non-executive employees to reflect actual wage in 2009 and to eliminate any pro forma increase in 2010," the order states. "For ratemaking purposes, the stipulation (settlement) also removed pay increases for the company's executives in 2009 and 2010."

The parties in the case included Avista, commission staff, the Idaho Forest Group, Clearwater Paper Corporation, the Idaho Conservation League, the Idaho Community Action Network and the Community Action Partnership of Idaho.

PacifiCorp, which does business in eastern Idaho as **Rocky Mountain Power**, filed a request for a 4 percent increase in September 2008 and was granted 3.1 percent effective April 18. This case was also resolved by a settlement of the parties.

PUC approves Rocky Mountain Power rate settlement

Case No. PAC-E-08-07, Order No. 30783
April 16, 2009

The Idaho Public Utilities Commission approved a settlement in the Rocky Mountain Power rate case that increases overall rates by an average 3.1 percent effective April 18.

The rate increase varies by customer class. For residential customers, the increase is 3.53 percent. For a customer who uses the utility's average of 850 kilowatt-hours per month, the increase is $2.38 per month in winter bills and $3.07 per month in summer bills. The increase to irrigation customers is 1.73 percent.

In September 2008, Rocky Mountain Power, which serves 70,000 customers in eastern Idaho, asked for a 4 percent overall increase and a 4.73 percent increase for residential customers. The utility asked to collect an additional $5.87 million in annual revenue. The settlement approved by the commission authorizes $4.38 million in additional annual revenue.

Parties signing the settlement include PacifiCorp (which does business as Rocky Mountain Power in eastern Idaho), the Idaho Irrigation Pumpers Association, the Community Action Partnership Association of Idaho and Public Utilities Commission staff, which operates separately from the commission.

The settlement also authorizes the development and funding of an energy conservation education program for low-income customers. Further, the company agrees to include a tiered-rate rate design proposal for residential customers when it files its next rate case.

Rocky Mountain Power maintained the increase is necessary to pay for growth in its electrical load, capital investment and operating cost increases beyond its control.

The parties to the case agreed that Rocky Mountain's purchase of the 500-megawatt Chehalis natural gas plant in Chehalis, Wash., was a prudent decision and in the public interest. Costs relating to buying and operating the plant were included in this case.

The settlement is a compromise, with no party accepting all the methodology or adjustments made to arrive at the $4.38 million in added revenue requirement. However, all parties agreed the overall increase represents a fair, just and reasonable compromise of the issues raised and that the settlement is in the public interest.

Other electric cases

Certificate for Langley natural gas plant approved

Case No. IPC-E-09-03, Order No. 30892
September 1, 2009

Idaho Power Company was granted a certificate to build a 330-megawatt natural gas-fired power plant four miles south of New Plymouth that is slated to begin operating in late 2012.

Without the new Langley Gulch Power Plant, Idaho Power risks falling short of meeting customer demand in four years. "The company has a statutory obligation to provide electric service and, since 2004, has forecast a need for a baseload generation resource in 2012," the commission said.

Idaho Power will build the plant on 137 acres of undeveloped range land adjacent to Interstate 84, immediately southwest of Exit 9 in rural Payette County.

Intervenors in the case, including the Industrial Customers of Idaho Power, the Idaho Irrigation Pumpers Association, the Idaho Conservation League and the Community Action Partnership Association of Idaho, said the project could be delayed because the rate of load growth has slowed with the economy. Further, they argued, Idaho Power could develop more energy efficiency and conservation programs.

After reviewing the record, the commission said the public interest was not served by delay. The commission said the lead-in time to develop a plant (about three years) is too long, that the company is already aggressively pursuing cost-effective conservation programs and there is a demonstrated need for more generation.

Using Idaho code adopted by the Legislature earlier in 2009, the commission granted the company "regulatory assurance" that it will receive recovery of its prudently incurred investment of $396.6 million in customer rates. Idaho Power sought preapproval assurance of $427.4 million. But the commission decided to separate costs that are known with greater certainty and competitively procured from amounts that are less certain.

Idaho Power must file quarterly reports on the progress of the project and a budget update showing total amount spent and billed and remaining contract dollars. Idaho Power maintains that the commission's regulatory assurance will make it easier to obtain capital from lenders at rates more favorable to customers.

Approval of the project did not immediately impact rates. Idaho Power wanted to include Construction Work in Progress (CWIP) in customer rates annually as it moved forward with construction. The commission denied that request, but said it is open to considering CWIP as construction progresses. An advantage of CWIP to customers, the company maintained, is a quicker recovery of construction costs, thus avoiding financing costs that would be assessed to customers over several decades.

The company's long-range plan to meet customer growth, called an Integrated Resource Plan, initially called for a coal-fired resource, but with rising concerns about climate change, the company revised its plan to call for a natural gas-fired baseload resource.

Idaho Power initiated a bid process that was reviewed by a third party. It received five valid proposals that represented 13 alternative sources, including a proposal by the company to build the plant itself. Idaho Power selected its own self-build plan, claiming it will have a revenue requirement impact of about $95 million less than the next competing proposal.

Intervenors argued the bid process was flawed, because, among other reasons, the bid evaluator was hired by the company, the process was not transparent enough, there was not an independent scoring by the bid evaluator and the company refused to consider any “build-and-transfer” projects, which would allow a third party to build the plant and then turn it over to Idaho Power to operate.

The commission acknowledged that the process could have been more transparent and that the “total universe of potential bidders was perhaps not realized.” However, the commission said, “Based on the evidence presented, we cannot conclude that a lower price and better project would have resulted” if the bid process had been better designed. Despite plant selection issues presented by the intervenors, it was apparent to the commission that the competitors were “sophisticated bidders and that the short list of projects were all competitive.”

In a separate case, the Northwest and Intermountain Power Producers Coalition has asked the commission to examine the current bid process. In the order, the commission said, “The actual and perceived flaws in the RFP (Request for Proposals) process, we find, while not fatal to the company’s resource selection, clearly demonstrate a need for a separate proceeding to consider RFP competitive bidding rules and guideline.”

While the intervenors advocated delay, several other parties submitting comments, including area cities, chambers of commerce and local businesses said additional energy infrastructure is needed and is a key element to attracting commerce and industry.

Idaho Power maintained that if Langley Gulch is delayed, any new large customers seeking to locate plant here would be advised that the company does not have firm resources sufficient to serve loads on a year-round basis. Further, the company warned, a delay could mean energy curtailments after 2012 under adverse circumstances such as low water, high temperatures, outages at distant generating plants, loss of transmission capacity or a combination of any of those.

Transmission costs are estimated to be about $25.4 million and will include construction of a new 18-mile 138-kV line from the plant to the Caldwell-Willis line, three miles from Caldwell Substation, and a 2.5-mile line from Ontario to Caldwell.

The plant is anticipated to employ up to 120 during the two years of construction and 18 full-time once it is operational.

Commission opens docket to pursue bidding guidelines

Case No. IPC-E-10-03
November 2009

As a result of questions raised during the Langley Gulch case (see above), independent power producers, as well as group representing industrial and irrigation customers, filed a petition in November asking that the Commission consider establishing competitive bidding guidelines for the procurement of major generation projects by Idaho’s three major electric utilities. However, Rocky Mountain Power, which operates in eastern Idaho, and Avista Utilities in northern Idaho are already subject to guidelines established by other states in which they operate. Because those utilities currently use those guidelines for projects that serve Idaho, the original application was modified to include only Boise-based Idaho Power Company.

The groups petitioning the commission contend that Idaho Power is free to issue bid requests that are “designed and administered completely without commission or other stakeholder input.” At year’s end, the case was still open.

Commission OK's installation of automated meters

Case No IPC-E-08-16, Order No. 30726
February 17, 2009

Idaho Power began in 2009 a three-year project to install automated meters throughout its southern Idaho service territory.

Responding to an urgent directive from the Commission, the utility is replacing its existing meters with advanced metering infrastructure (AMI) that will allow customers to monitor electric prices and adjust their use to take advantage of lower price-periods. Idaho Power submitted a cost estimate of $71 million for the project and will absorb any costs above that. Rates did not immediately increase, but are being included in base rates as the meters are placed in service. ***(See pgs. 18-19 for first installment of AMI expense in base rates.)*** The commission also approved the company's request to accelerate the depreciation time frame on its existing meters down to three years.

The commission is urging Idaho Power to "move forward with all deliberate speed" with installation beginning this year in the Boise area, then in 2010 in the Canyon and Payette regions and, finally, in 2011 in the Magic Valley, Pocatello and Salmon areas.

The advanced meters can be read from a remote location, negating the need for an Idaho Power representative to access customer properties. They can provide the company and individual customers with hourly meter readings and inform customers of current electric prices, potentially allowing them to manage their use and reduce their bills.

Other benefits to customers and the company will include reduced operational costs associated with meter reading and improved meter reading accuracy, outage monitoring and theft detection. Customers can also be disconnected and reconnected from a remote location saving time and labor. There are also billing advantages such as fewer estimated bills, less re-billing and more flexible billing schedules.

After the Western energy crisis of 2000-2001, the commission said advanced metering technology was becoming more necessary. At that time, the commission ordered Idaho Power to evaluate and report on advanced metering technology. In 2002, the commission ordered Idaho Power to complete installation of advanced metering by 2004, but financial and technical problems made it impossible for the company to meet that time frame.

The commission eventually adopted a phased-in implementation and evaluation approach, with advanced meters installed in test areas such as Emmett. In an earlier order, the commission stated … "the potential benefits of advanced metering to ratepayers and the company are too great to delay … implementation indefinitely."

The Idaho Conservation League endorsed adoption of the AMI program, saying it will encourage customers to be more efficient, which will lead to a decrease in overall electrical demand and reduce carbon dioxide emissions. AARP Idaho opposed the plan, saying more information should be obtained through a technical hearing before imposing the additional cost of AMI on customers.

The commission said it is mindful of the large capital expense, but said it expects Idaho Power to "demonstrate its ongoing effort to reduce operating costs and increase efficiencies and reminds the company that in the current economic climate its fiscal responsibility will be reviewed extensively and continually."

Idaho Power applies to make Fixed Cost Adjustment permanent

Case No. IPC-E-09-28, Order No. 30948
December 8, 2009

Late in the year, Idaho Power Company asked the Commission to make permanent a pilot program that allows the utility to recover its fixed costs of delivering energy regardless of the impact energy efficiency and conservation programs have on energy sales.

The Commission implemented the Fixed Cost Adjustment (FCA) in 2007 as a three-year pilot program. The adjustment, sometimes referred to as a “decoupling mechanism,” allows Idaho Power to recover its fixed costs of delivering energy as established in its most recent general rate case even if there is a reduction in energy sales and revenues because of energy efficiency and demand reduction efforts.

Without a mechanism like the FCA, Idaho Power claims there is a financial disincentive for it to promote energy efficiency and conservation programs because energy sales may decline. The FCA allows Idaho Power to recover its established fixed costs through a surcharge when it under-collects fixed costs because of reduced electrical use. Conversely, if Idaho Power collects more than its established fixed costs, customers receive a credit instead of a surcharge.

During the first year of the pilot, the FCA resulted in a credit of about 48 cents per month on an average residential bill. During the second year, customers were assessed a surcharge, or an increase of about 56 cents per month on an average residential bill. The FCA applies only to residential and small-business customers.

Idaho Power claims that implementation of the FCA has been a major factor in the utility’s substantial increase in its level of investment in energy efficiency and conservation, from $11.5 million in 2006 to $21.2 million during 2008. That investment has resulted in significant increases in the number of megawatt-hours saved – a 29 percent increase after the first year and a 54 percent increase after the second year. According to the company’s figures, the megawatt-hours saved during 2006 was 70,766; during 2007, the total saved was 91,145; and during 2008, the total was 140,156.

The case was still being reviewed at year’s end.

Commission adopts changes to PCA calculations

Case No. IPC-E-08-19, Order No. 30715
January 16, 2009

The Commission has approved changes in the way the annual Power Cost Adjustment (PCA) is calculated in hopes of decreasing the volatility in the rate adjustment, which can be either a one-year surcharge on customer bills or a one-year credit.

The normal costs for supplying power to customers are recovered in a utility’s base rates. However, a utility may incur higher than normal costs from unusual circumstances, such as low-water conditions or higher than anticipated market conditions. In those circumstances, the commission approved a PCA process that enables Idaho utilities to recover higher than normal costs. Revenues from a PCA surcharge are used only to pay the increased power costs and do not increase company earnings.

The PCA becomes effective June 1 every year. Because water conditions have been lower than normal and the market more volatile, customers have experienced wide variations in the PCA in recent years. The 2008

PCA was an average 10.7 percent increase for customers. In 2007, the surcharge was an average 14.5 percent increase. However, in 2006, there was an average 19.34 percent credit to customer rates.

To address the fluctuations in the PCA, the commission directed Idaho Power Co., commission staff and representative of customer groups to participate in workshops. Customer groups participating included those representing commission staff, Idaho Power, irrigation customers, industrial customers, Micron and the U.S. Department of Energy. The workshops resulted in a settlement agreed to by all parties and later approved by the commission.

Major components of the agreement include:

1) Since the 1992 inception of the PCA, 10 percent of the power supply costs above base rates were absorbed by the company and customers paid the remaining 90 percent in the form of the surcharge. Conversely, during those years when there was a credit, Idaho Power got 10 percent of the savings and customers received 90 percent.

The settlement adopted by the commission changes that sharing mechanism to require customers to pay 95 percent of above-normal power supply expense. During years when there is a credit, customers would get 95 percent of the savings. The sharing mechanism was put in place to incent the company to make wise decisions when purchasing energy because the company would be responsible for 10 percent of the costs of those decisions. However, since 1992, the volatility in power supply expense scenarios has increased from about $100 million to $330 million. The settlement proposes, and the commission agrees, that with a 95/5 share, the company's risk and possible loss would be about the same proportionately as it was under the 90/10 share. "We do find that power supply cost volatility has increased significantly since the PCA was implemented, and that with increased volatility , a sharing percentage of 5 percent still provides strong incentive for the company to make prudent power purchases," the commission said.

A further reason for the change to 95/5 is that after the 2000-01 Western energy crisis, the commission directed Idaho Power to develop a risk management policy that provides less discretion to Idaho Power when making its energy sales and purchases.

2) The settlement also adopts changes in the Load Growth Adjustment Rate, or LGAR. The LGAR acknowledges that Idaho Power's revenues will increase between rate cases due to customer growth and changes in customer use. About $31.40 per megawatt-hour was subtracted from power supply expense to account for that growth. The settlement's new methodology recognizes that the company also incurs additional power supply costs to serve new load between rate cases and has no opportunity to collect those costs. Therefore, the settlement reduces the LGAR to $28.14 per MWh.

3) A third component of the settlement makes changes to the formula for determining forecasted power supply expenses. The former methodology created unreasonably large true-ups between forecasted power supply costs and actual costs. The new method is designed to reduce that difference.

4) A fourth component allows Idaho Power to include third-party transmission expense in the PCA not already included in base rates. During 2007, third-party transmission costs were about $13 million. "We find that third-party transmission costs are incurred in conjunction with market purchase and sales and should be tracked through the PCA, like other variable power supply costs," the commission said.

Commission rules on building contractors', highway districts' petitions

Case No. IPC-E-08-22, Order No. 30955
December 2, 2009

The Commission granted in part and denied in part a petition for reconsideration filed by area highway districts and, in the same case, denied a petition for reconsideration by the Building Contracts Association. Both parties then appealed to the state Supreme Court where the case is pending at the filing of this report.

The petitions pertain to an order issued in July 2009 that approved increases and updates in Idaho Power's "Rule H tariff," which lists the charges that developers and new customers must pay for new line installations and service attachments. Idaho Power said it sought to update the tariff in an effort to shift a greater portion of the cost of new construction from existing customers to developers and new customers requesting the construction,

The changes also allow Idaho Power to include new language in the tariff dealing with who pays for the relocation of utility facilities when private development forces the utility to relocate an existing distribution line in a public right-of-way.

The Building Contracts Association objected to the new fees for line installations and service attachments for new customers, claiming they discriminate against new customers.

The Ada County Highway District, the City of Nampa and the Association of Canyon County Highway Districts objected to new language in the tariff that, they said, intruded on their authority to determine who pays and when payments are made for utility facility relocation in public rights-of-way. Idaho Power proposed language that would have required developers, rather than Idaho Power customers, to pay for utility facility relocation in advance of the project's completion when the developer is a private entity and not a transportation agency requiring relocation for public benefit.

Building Contractors' objection

In its July order, the commission ruled that, effective Nov. 1, developers of subdivisions and multiple-occupancy projects will receive from Idaho Power a $1,780 allowance for each single-phase transformer installed within a new development and a $3,803 allowance for each three-phase transformer. The same allowance is provided for each single-phase and each three-phase service customer outside a subdivision. Developers will be responsible for any costs above the allowance.

The increased allowance was adopted in place of an $800 per lot refund developers now get as customers move on to the lots and begin receiving electric service. However, developers can still get "vested interest refunds" for additional line installations inside a subdivision that were not part of the initial line installation.

The commission agreed with Idaho Power that the new allowance should be based on the actual cost of most commonly installed facilities, rather than basing the allowance on the number of customers (lots), as was the case in the previous Rule H tariff. Basing the allowance on customers rather than the actual cost of the installed facilities could lead to allowances inside subdivisions that are greater than the cost of the facilities, the commission said.

In its order, the commission said it is "addressing a fundamental principal of utility regulation: To the extent practicable, utility costs should be paid by those who cause the utility to incur the costs. If the 'cost-causers' do not pay, the electric rates for other customers will be higher."

The Building Contractors maintain the updated allowance "approves an inherently discriminatory rate structure" by imposing unequal charges for new customers receiving the same level of service as existing customers. The contractors say inflation, not customer growth, is the actual source of increased costs to extend utility facilities.

The commission denied the Building Contractor's petition in its entirety.

Highway districts' objections

When utility line relocation is requested by local or state government for transportation or other public improvements, Idaho Power and its customers pay for the relocation. Idaho Power said it has no issue paying for utility relocations for public benefit, but objects to having its customers pay for what it deems to be private or third-party benefit.

"Idaho Power customers in Pocatello do not benefit from roadway improvements for a new shopping center in Nampa, but they currently pay for relocation costs in excess of the public benefit in their rates," Idaho Power stated in its response to the highway districts petition for reconsideration.

The highway districts alleged that the new language requiring third-party reimbursement intrudes in the highway districts' exclusive jurisdiction and is unconstitutional because it obligates local government entities, such as Local Improvement Districts (LIDs) to pay for utility relocation costs.

They highway districts also objected to Idaho Power's classification of LIDs, which are created by local governments to pay for physical improvements, as "third-party beneficiaries" that can be required by Idaho Power to pay for utility relocation when a private party benefits.

Idaho Power did not contest public road agencies' authority to require relocation of utility facilities at the utility's expense when there is a public benefit. Idaho Power argued that once the utility complies with the relocation it can seek reimbursement from third parties benefitting from the relocation. Idaho Power said only the Public Utilities Commission has the authority to determine how utility costs should be allocated.

In its findings, the commission disagreed with the company's contention that LIDs are always third-party beneficiaries and thus must always be required to pay for utility relocation. The commission said it is reasonable for an LID to include relocation costs, but it declined to include language that compels reimbursement from LIDs.

The commission also denied Idaho Power's request to require advance payment from third parties who benefit from utility facility relocation. The highway districts said such a requirement could unduly interfere with a project's timetable if the third party did not make timely payment.

The commission said Idaho Power has other alternatives to ensure it receives reimbursement including its ability to participate in project development meetings at the onset of the project and its ability to terminate service is the developer refused to pay. In fact, the commission added a new section to the tariff that requires Idaho Power to participate in project design or development meetings to be in a better position to eliminate or minimize relocation costs to the maximum extent reasonably possible. That new section, the commission said, complies with a law passed by the Idaho Legislature this year with the intent of minimizing the cost of utility relocation where possible.

The commission declined to grant the highway districts' request that the new language be eliminated because the commission lacked jurisdiction. "The commission affirms that highway agencies have the authority to determine when Idaho Power must relocate its distribution facilities and whether any other party is responsible for paying for the road improvement costs," the commission said. "However, once the highway agency determines that a private party (e.g., a developer) must shoulder all or a portion of the road improvement costs, then it is the Commission that establishes the costs for utility relocation." The commission said that relocation of utility facilities is a utility service subject to commission jurisdiction.

PUC backs legislation allowing proposed low-income programs

Case No. GNR-U-08-01, Order No. 30724
February 4, 2009

The Commission is endorsing legislation that would allow utilities to propose "programs, policies and rates" that may assist low-income customers in their effort to pay energy bills.

It is one of several recommendations made by the commission in response to energy affordability workshops recently conducted by commission staff, the utilities and several consumer groups. The commission directed the state's major utilities to participate in the workshops in response to a "variety of factors contributing to significant upward pressure on electric and natural gas rates in Idaho." Energy affordability has become a central issue for many Idaho residents and businesses, the commission said.

A report summarizing the recommendations and conclusions from the workshops, as well as the positions of all the participating parties, is available on the commission's Web site at www.puc.idaho.gov.

Parties who participated in the study included commission staff, Idaho Power Company, Rocky Mountain Power, Avista Utilities, Intermountain Gas, the Northwest Industrial Gas Users, the Community Action Partnership Association of Idaho, AARP, the Idaho Community Action Network and the Snake River Alliance.

The legislation the commission is recommending would change current statute, Idaho Code 61-315, that prevents public utilities from granting "any preference or advantage" to persons or corporations when it establishes rates.

The commission said the change in the legislation should not compel Idaho utilities to offer low-income financial assistance programs, but should allow them to do so without violating current Idaho statute. "The legislation should allow the utilities flexibility in the programs to be proposed," the commission said.

The commission specifically pointed to a program offered by Avista Utilities, which operates in northern Idaho, but also has customers in Washington and Oregon. Avista's Low-Income Rate Assistance Program, or LIRAP, provides funds to help low-income residents in Washington and Oregon pay their energy bills. In Washington, the money for the program is collected through a rider on all customer bills. In Oregon, LIRAP is funded by an assessment on natural gas bills.

Offering more low-income programs at a state level may qualify Idaho for more federal funding under the federal Low-Income Home Energy Assistance Program or LIHEAP. During 2008, 101,000 Idaho households qualified for LIHEAP assistance, but only 32,843 of those households received assistance due to the lack of federal LIHEAP funding.

LIHEAP's Idaho allocation can be increased through a process called "leveraging". The federal government withholds a percentage of LIHEAP money allocated to each state as an incentive for that state to first acquire non-federal funds for assistance to low-income households. Grants are awarded states that can provide more local funding.

Other steps the commission is encouraging:

- Utilities should engage in greater education efforts to make more customers aware of the programs already available to help with paying energy bills and to offer weatherization and conservation steps that can be taken to decrease energy bills. "Education and funding regarding weatherization and conservation can be administered in conjunction with LIHEAP and LIRAP-type programs," the commission said.

- Weatherization programs should be extended beyond single-family residential homes to also include apartment and condominium complexes, manufactured homes and rental housing.

- Utilities should advocate for the adoption of greater energy efficiency standards for new construction.

- Utilities should work with local lenders to provide opportunities for customers, including low-income customers, to move to higher-efficiency appliances. Several utilities offer rebates to customers who switch to higher-efficiency appliances. "Unfortunately, upgrading an appliance is a luxury that low-income customers cannot generally afford," the commission said.

- The commission will continue to support the use of tiered-rates as a means to encourage greater energy efficiency and conservation. The recently concluded Idaho Power rate case implements a three-tiered rate structure with gradual increases to rates as use increases.

- The commission is encouraging utilities to be flexible in making payment arrangements "that are based on the customer's unique circumstances and ability to pay." However, the commission said, "Flexibility by the utility should not be mistaken for abandonment of debt."

- Most Idaho utilities require customers they consider to be high-risk to pay deposits before they can receive electric or gas service. The utilities should periodically evaluate whether requiring some customers to pay connection deposits is cost-effective, the commission said. Idaho Power Co., for example, determined that administrative costs associated with a deposit mechanism did not justify continuing the program.

- The commission commended Avista Utilities for its "case management program" which assigns a case worker to provide individual, specialized attention to customers having problems paying their bills. Intermountain Gas is in the process of developing such a program. The commission said it won't require all utilities to have a case management program, but encouraged utilities to be "flexible in responding to their customers' needs."

PacifiCorp relies on renewable energy to meet future needs

Case No. PAC-E-09-06, Acceptance of Filing
September 17, 2009

The commission accepted a planning document filed by PacifiCorp that details how the utility intends to meet customer needs over the next decade. The utility serves customers in Washington, Oregon, Utah, Wyoming, California and in eastern Idaho, where, operating as Rocky Mountain Power, it has about 70,000 customers.

PacifiCorp plans to add more than 1,423 megawatts of renewable energy and does not include any added coal generation in its plan.

The commission requires that regulated electric utilities file an Integrated Resource Plan (IRP) every two years. Acceptance of the plan by the commission does not guarantee that it will approve every project proposed during the 10-year period. "The IRP, as we continue to note, is a utility planning document that incorporates assumptions and projections at a point in time. It is the ongoing planning process that we acknowledge, not the conclusion or results," the commission said.

PacifiCorp said it will begin to experience a capacity deficit in 2011 if steps are not taken soon to increase generation and reduce demand. The utility anticipates a growth rate of about 2.5 percent per year over the next decade. Further creating the need for more generation is the 2011 expiration of a major power purchase contract with the Bonneville Power Administration.

The vast majority of the 1,423 MW in anticipated new renewable generation is expected to come from wind (1,313 MW) with the rest coming from geothermal (35 MW) and major upgrades to existing hydroelectric facilities (75 MW).

On the conservation side, the utility plans to save just more than 900 MW from energy efficiency programs and another 105 to 325 MW from programs where the company remotely reduces demand from customers such as irrigators and industry during times of peak use. PacifiCorp also plans to add about 831 MW in gas-fired capacity between 2014 and 2016 and gain 170 MW of emissions-free capacity from coal plant turbine upgrades.

The company could have been short on capacity as soon as 2010, but took steps to meet increased demand in 2008 by acquiring a 520-MW natural gas plant in Chehalis, Washington, and adding 175 MW of additional wind resources.

PacifiCorp anticipates gaining access to more generation with the completion of its proposed Gateway transmission project, a joint project with Idaho Power Co. that will transport energy from eastern Wyoming, through southern Idaho (Gateway West) and through Utah (Gateway South).

Commission staff, which operates independently of the commission, commended the company for a diverse mix of generation resources, while adhering to imposed and pending environmental regulation. Staff found it noteworthy that coal-fired generation does not appear in the company's portfolio of future generation sources.

Staff did express concern that the company anticipates a more than doubling of the wind integration cost assessed wind developers. The company's 2007 IRP used a cost of $5.10 per megawatt-hour to integrate wind, but includes an $11.75 per MWh cost in the current IRP. Staff also said that costs included by the company to meet mandated renewable portfolio standards in other states were not adequately quantified.

Renewable energy

Commission orders Idaho Power to sell Green Tags

Case No. IPC-E-08-24, Order No. 30743, Order No. 30018
May 21, 2009

Reversing an earlier decision, the commission ordered Idaho Power Co. to sell its 2007 and 2008 Green Tags and use the proceeds – estimated to be between $1.6 million and $1.9 million – to benefit ratepayers.

A Green Tag, or Renewable Energy Credit, is issued to each utility for every megawatt-hour of electricity generated by an eligible renewable energy resource. An active market exists for the purchase and sale of Green Tags. Idaho Power's Elkhorn Wind project in Oregon and its Raft River geothermal project in south-central Idaho generated more than 320,000 MWh of Green Tags for Idaho Power in 2007 and 2008.

In January, the commission granted Idaho Power's request to retire its Green Tags. Idaho Power wanted to retire the tags in anticipation of federal or state legislation that may require utilities to generate a specific amount of energy from renewable sources. By retiring the tags, Idaho Power said it could represent to renewable energy certification programs and to its customers that it is meeting customer expectations for increased use of renewable energy.

The Industrial Customers of Idaho Power petitioned the commission for reconsideration, arguing the value associated with the Green Tags belongs to the ratepayers and should be sold to benefit customers. Further, the industrial customers argued, allowing the utility to retire the tags causes them to lose value in the wholesale market.

The Idaho Conservation League and the Renewable Northwest Project argued that the commission should affirm its original decision to let the utility retire the tags.

During reconsideration, Idaho Power modified its request, asking for authority to retire or "bank" the tags. Banking the tags would allow the company to stockpile tags now, when they are presumably less expensive to acquire, in anticipation of future mandatory renewable energy requirements.

In its order, the commission said it found no compelling evidence that banking the tags will "lessen the company's burden in meeting a federal future standard." Idaho Power's request to bank or shelve the tags rests only on speculation that they may be used in the future, the commission said. "Unless and until the federal government establishes renewable energy standards and corresponding guidelines, we find the most prudent disposition of these Green Tags, at this time, is their sale." However, the commission said, this order does not foreclose an alternative treatment for Green Tag sales in the future.

Utility reports more emissions credits; proceeds from previous credits used to expand energy efficiency education

IPC-E-09-08, Order No. 30790 and Case No. IPC-E-08-11, Order No. 30760
May 1, 2009

The commission ruled that revenue from Idaho Power Company's sale of sulfur dioxide emission allowances should be included in the utility's annual Power Cost Adjustment to benefit customers.

Idaho Power earned about $5.3 million from the sale of the allowances during 2008 and part of 2009, after deducting brokerage fees. At least 90 percent of the revenue from those sales will go to ratepayers.

In 2007 and 2008, proceeds from the sale of emission allowances were deducted from the Idaho Power's annual Power Cost Adjustment (PCA), reducing the size of that surcharge for customers. The commission late last week concluded a case that directs a portion the 2008 adjustment – $500,000 – to an expanded energy education program in Idaho Power's territory.

A 1990 amendment to the Clean Air Act established a national program for reducing acid rain. Sulfur dioxide (SO_2) and nitrogen oxide (NOx) are the primary causes of acid rain. In the United States, about two-thirds of all SO_2 and one-fourth of all NOx comes from thermal (coal and natural gas) electric generating plants. Idaho Power has an ownership interest in three coal-fired plants: Jim Bridger in Wyoming, North Valmy in Nevada and Boardman in Oregon.

Under the federal program, thermal power plant owners are issued limited allowances for their plants' sulfur dioxide emissions based on a specific plant's past emissions and a nationwide cap placed on the total amount of SO_2 that can be emitted. Each allowance authorizes the utility to emit one ton of SO_2. At the end of each year, a utility generating unit must hold allowances equal to its allotted annual SO_2 emissions. A utility that holds over its annual requirement is considered to have surplus allowances that can be sold on the open market or through auctions sponsored by the Environmental Protection Agency.

Proceeds from previous case should go to energy efficiency education

Case No. IPC-E-08-11, Order No. 30760
May 1, 2009

The commission chose a modified version of a proposal by Idaho Power as the best use of $500,000 for energy efficiency education. In the 2008 emissions credits case, the commission agreed with a recommendation from the Idaho Energy Education Project that a portion of $19.6 million in emissions credits be used for energy education. Proposals for an education program came from IEEP, Idaho Power Co. and a joint proposal by the Office of Energy Resources and the State Department of Education.

The commission adopted the Idaho Power proposal, saying it is more focused on schools within its service territory and has smaller overhead and administrative costs.

Idaho Power's proposal includes expanding its existing program of energy education by increasing the number of energy audits for homes and schools as well as follow-up discussion of those audits.

Idaho Power will distribute classroom energy kits to students to take home. Students will be taught how to read meters, including advanced meters that are being installed throughout Idaho Power's territory. With meters the students take home, they will be able to calculate the energy use of home appliances. Students will also be invited to participate in audits of school buildings, including making recommendations for efficiency measures.

The commission rejected a portion of Idaho Power's proposal to add two more solar projects to the two existing projects in the Solar 4R Schools program. The commission said the $75,000 allocated for those projects would be better used in the home and school energy efficiency components of the program.

The commission also directed Idaho Power to establish an advisory board to implement the energy education proposal. Its members will include some of the parties who participated in the case. The board will also assist Idaho Power in preparing a final report to the commission after the two-year project is complete.

Commission reviews Avista conservation programs
Case No. AVU-E-09-06 and AVU-G-09-04, Order No. 30918
October 7, 2009

The commission approved an application by Avista Utilities to increase the rider that electric and natural gas customers pay to fund conservation programs and to create a mechanism for a yearly adjustment each spring.

The Commission's decision did not result in an increase to the overall rates approved by the commission in its July 17 order and made effective on Aug. 1. That increase – an average 1.5 percent for electric customers and 1.2 percent for gas customers already included the proposed rider adjustments.

The rider funds more than 30 programs in two categories called demand side management (DSM) and energy efficiency. DSM programs reduce customer demand on the company's generation sources. Efficiency programs help customers use their electricity more efficiently. The commission approves riders for electric and gas utilities if they are found to be cost-effective for both customers and the utility. DSM and efficiency programs can save customers money in both the short term by direct customer participation and in the long term because they prevent or delay the utility from having to buy or build more expensive generation.

Avista proposed to increase its electric rider from 2.24 percent to 3.27 percent of customer bills and the gas rider from 1.55 percent to 2.6 percent. Final approval of the rider would increased annual revenue by $5.4 million. However, increases in the rider cannot increase or decrease company earnings. Revenue collected from the rider can be used only to pay off a $2.36 million shortfall in the electric rider fund, a $1 million shortfall in the gas rider fund and to fund ongoing programs.

Avista's DSM and efficiency efforts are based on providing financial incentives or rebates for customer participation in more than 30 programs. Some of the programs include efficiency measures for appliances, compressed air systems, HVAC systems, industrial and commercial equipment, lighting and motors. The programs also include renewable technologies and sustainable building measures. Further, Avista has long encouraged the direct use of natural gas by its electric customers with rebates for the conversion of electric-to-natural gas space and water heater loads.

According to the company's application, Avista continues to exceed targets in electric and gas savings as the result of these programs for its Washington and Idaho customers. More than 110 average megawatts of demand-side management programs are now in place on the company's total retail average load (during 2008) of 1,100 average megawatts. (A megawatt is one million watts, enough electricity to power about 650 average homes.) On the gas side, 1.9 million therms were saved during 2008, which was 136 percent of the company's target.

Of all the surcharge revenues collected from Washington and Idaho electric and gas customers, 72 percent were paid back to customers in direct incentives to participate in energy efficiency and demand-side management programs. This does not include the additional benefits such as technical analysis and education provided to customers by the company's DSM staff.

In the application, Avista also proposed to reduce large negative or positive adjustments to the rider by filing on or about Feb. 15 of each year for either an increase or a decrease to the rider.

According to the company's application, installing energy efficiency measures "is a direct action customers can take to respond to a period of increasing energy prices facing the Pacific Northwest and the country as a whole." The application stated that Avista's energy efficiency programs are being used by customers at unprecedented levels.

PacifiCorp rates will be adjusted annually to account for power supply

Case No. PAC-E-08-08, Order No. 30904
October 7, 2009

Rates for customers of Rocky Mountain Power will be adjusted either up or down every April 1 to account for varying costs of power supply needed to serve the utility's eastern Idaho customers.

The Commission adopted a negotiated settlement that allows a yearly rate adjustment called the Energy Cost Adjustment Mechanism, or ECAM, for PacifiCorp, which does business in eastern Idaho as Rocky Mountain Power. The ECAM will be either a one-year surcharge (increase) to customer bills or a one-year credit (decrease) depending on the company's power supply expenses that are not already included in the fixed base rates paid by customers.

A greater portion of PacifiCorp's generation now comes from natural gas. The utility also gets about 30 percent of its generation from hydropower. Changing water conditions and volatility in the natural gas markets can cause fluctuations that sometimes result in power supply expense that is greater than that already included in base rates and sometimes in power supply expense that is less than that included in base rates. When those expenses are higher, customers will get a surcharge and when they are lower, a credit.

The commission said the yearly adjustment is "supported by the volatility in the energy market and the changing character of the company's resource portfolio."

"The commission finds that the designed ECAM will send better price signals to the company's customers of the cost of power by adjusting their rates on a more current basis," the commissioners said.

A benefit to customers, even if the ECAM is a surcharge, is that a more timely recovery of power supply expenses should reduce for the frequency of filings by the company for general rate increases. As part of the agreement approving the ECAM, PacifiCorp agreed not to file a rate case before May 1, 2010.

Another benefit to a yearly adjustment is lower borrowing costs for the company. PacifiCorp is in a period of increased investment, thus assurances to financial markets of timely recovery of expenses allows for financing at lower interest rates, benefitting both the company and its customers.

To incent the company to be prudent in its power supply purchase decisions, the ECAM requires that shareholders pay 10 percent of the power supply expenses not already included in rates.

The Idaho Irrigation Pumpers Association supported the settlement. Other utilities serving Idaho customers have annual rate adjustments similar to PacifiCorp's ECAM. Idaho Power Company, which serves customers across southern Idaho, and Avista Utilities, which serves customers in northern Idaho, both have an annual Power Cost Adjustment, or PCA.

PacifiCorp serves about 70,000 customers in eastern Idaho.

PacifiCorp wants larger discount for non-firm wind generation

Case No. PAC-E-09-07, Notice of Comment Deadline
October 5, 2009

PacifiCorp, which does business as Rocky Mountain Power in eastern Idaho, is asking state regulators that it be allowed a larger discount from the price it must pay wind developers for their generation.

Currently, PacifiCorp discounts $5.10 per megawatt-hour off the rate it pays some wind developers. The discount is intended to capture PacifiCorp's cost of integrating wind generation into its electrical system. PacifiCorp is asking the Idaho Public Utilities Commission that it be allowed to discount $9.96 per MWh from the rate is must pay small-wind developers who qualify under the provisions of the federal Public Utility Regulatory Policies Act of 1978 (PURPA).

Under PURPA, qualifying generators of small-power projects that generate up to 10 megawatts are paid a rate published by the commission. That rate, called an avoided-cost rate, is to represent the cost the utility avoids by buying output from the small-power project instead of generating the power itself or buying it from another power provider.

PacifiCorp's application does not apply to wind developers who enter into agreements with the utility to deliver output on a firm, hourly basis.

The case was still pending at the time this report was completed.

PUC approves demand reduction contract

Case No. IPC-E-09-02, Order No. 30805
May 21, 2009

The Commission approved a five-year agreement between Idaho Power Company and Boston-based EnerNOC to reduce demand from commercial and industrial customers by at least 2 megawatts this year and by at least 50 megawatts in each 2012 and 2013. EnerNOC, selected in a bid process, will implement and operate the program.

According to Idaho Power, the total five-year cost for the program is $12.2 million, varying from about $315,000 this year to about $3.5 million in the fifth year. Costs associated with the program will be recovered from the Energy Efficiency Rider funds.

Commercial and industrial customers who volunteer to participate would be asked to reduce their energy loads for two to four hours during those summer days when demand on Idaho Power's generation system is at its peak. Participants would receive compensation in exchange for reduced loads.

The commission said Idaho Power has selected a "capable entity with significant experience in negotiating and securing the necessary load reduction agreements." The commission is satisfied that the agreement contains adequate protection for the company and ratepayers should EnerNOC fail to deliver on its demand reduction requirements.

PURPA projects

Commission updates rates to be paid developers of small-power projects

Case No. GNR-E-08-02, Order No. 30738
Case No. GNR-E-09-01, Order No. 30744
March 17, 2009

Developers of qualifying renewable small-power projects will be paid considerably more for their generation as a result of updated published rates.

The Commission updated both the fuel and non-fuel components of a mechanism used to calculate the rates that Idaho's three major regulated utilities must pay to small-power or cogeneration project developers whose projects qualify under the federal Public Utility Regulatory Policies Act, or PURPA.

PURPA, passed by Congress during the energy crisis of the late 1970s, requires electric utilities to offer to buy power produced by qualifying small-power producers or cogenerators. The rate that utilities must pay project developers, called an "avoided-cost rate," is determined by state commissions. The avoided-cost rate is to be equal to the cost the utility avoids if it would have had to generate the power itself or purchase it from another source. In Idaho, projects cannot be larger than 10 megawatts to qualify for the published avoided-cost rate.

The commission recently issued two orders; one that updates the non-fuel components of the avoided-cost rate, such as capital costs and operations and maintenance and another that updates the always varying fuel components of the rate. The fuel component is adjusted shortly after the Northwest Power and Conservation Council releases a new natural gas price forecast, which it did in late December.

The result of both orders is an avoided-cost rate that is considerably higher than the former rate paid by utilities to small-power producers. For example, the developer of a wind farm or geothermal facility with a capacity of less than 10 MW would be paid $88.67 per megawatt-hour (or about 8.87 cents per kWh) for a 20-year levelized (same rate all 20 years) contract with Avista Utilities. That compares to the former avoided-cost rate of $70.12 per MWh.

The three major investor-owned utilities in Idaho – Idaho Power, PacifiCorp and Avista Utilities – participated in the case as did Black Canyon LLC, which is developing a wind generation facility in Bonneville County.

PacifiCorp, which does business in eastern Idaho as Rocky Mountain Power, filed a motion to delay implementing the new avoided-cost rate and, in the absence of a delay, asked the commission to decrease the size of projects that can qualify for the published rate from 10 MW to no larger than 1 MW. PacifiCorp contended the Northwest Power and Conservation Council natural gas price forecast was too high given the recessionary economic environment.

The commission said PacifiCorp did not present enough evidence that the rate is not reasonable. Further, the commission said, any utility can petition the commission at any time if it believes the mechanism used to calculate the rate is unreasonable.

Anaerobic digester to sell output to Idaho Power

Case No. IPC-E-09-22, Order No. 30874
August 14, 2009

The Commission approved a sales agreement allowing Idaho Power Co. to buy the output from the Bettencourt B6 dairy anaerobic digester located near Jerome.

The agreement, between Idaho Power and Cargill Environmental Finance, is for 2.13 megawatts. The purchase price will be equal to 85 percent of a Dow Jones market price that is the weighted average of the daily on-peak and off-peak price for non-firm energy.

The project is scheduled to in operation by September 1. After the project has operated for a reasonable amount of time, Idaho Power expects that Cargill and the company will enter into a long-term firm energy sales agreement.

Idaho Power will buy energy from three Hagerman area wind farms

Case Nos. IPC-E-09-18, Order No. 30924; IPC-E-09-19, Order No. 30925;
IPC-E-09-20, Order No. 30926
October 15, 2009

The Commission approved three energy sales agreements between Idaho Power Company and a Boise-based wind developer who will build three wind farms in the Hagerman area.

The sales agreements are with Exergy Development Group of Idaho, which plans to build all three projects under the provisions of PURPA, the Public Utility Regulatory Policies Act of 1978. PURPA requires electric utilities to offer to buy power produced by qualifying small-power producers or co-generators. The rate to be paid project developers, called an "avoided cost rate," is to be equal to the cost the electric utility avoids if it would have had to generate the power itself or purchase it from another source.

The three projects – Camp Reed (22.5 MW), Payne's Ferry (21 MW) and Yahoo Creek (21 MW) – are scheduled to begin operating Sept. 30, 2010. Under the agreements, each of the plants will deliver up to 10 average megawatts on a monthly basis, which is the upper limit of the size of projects that can qualify for PURPA posted rates.

The projects are among the first PURPA wind agreements signed since the resolution of a major case involving all of Idaho's regulated electric utilities and wind developers. Because of the intermittency of wind generation and its impact on the utility transmission grid, the posted rate paid to wind developers is reduced to reflect the utility's cost of integrating the generation into its system. Wind developers must also provide mechanical guarantees and share in the expense of wind forecasting.   In exchange, the utilities agreed to drop a provision that penalized wind developers if their actual generation output was less than 90 percent or more than 110 percent of their projected output.

These wind agreements are also unusual in that the contracts are for levelized rates rather than non-levelized rates. Levelization means that the developer is paid an energy price at the front-end of the 20-year agreement that is in excess of the actual energy value. The overpayment is recouped in later years when the payments are projected to be less than the value of the power. Levelized rates can be an incentive to cogeneration and small-power development because it helps project developers recoup up-front expenses more quickly. But few developers choose this option because of the accompanying security requirements put in place to discourage contract default. In the event of a default, some project owners may not be unable to refund the utility the overpayment that comes in the early years of a levelized contract.

The developer of these three wind projects has agreed to meet various security requirements in addition to a maintenance reserve account of at least $2 million.

Under the 20-year contracts, Idaho Power will pay the posted rate of $84.40 per megawatt-hour during months of normal demand, which include January, February, June, September and October. During the months of heavy demand (July, August, November and December), Idaho Power will pay $102.58 per megawatt-hour. During months of less-than-normal demand (March through May), Idaho Power will pay $61.47 per megawatt-hour. Those rates include the wind integration charge and are adjusted slightly during heavy-load hours and light-load hours of the day.

Commission approves Idaho Power agreement with wind project

Case No. IPC-E-09-25, Order No. 30964
December 18, 2009

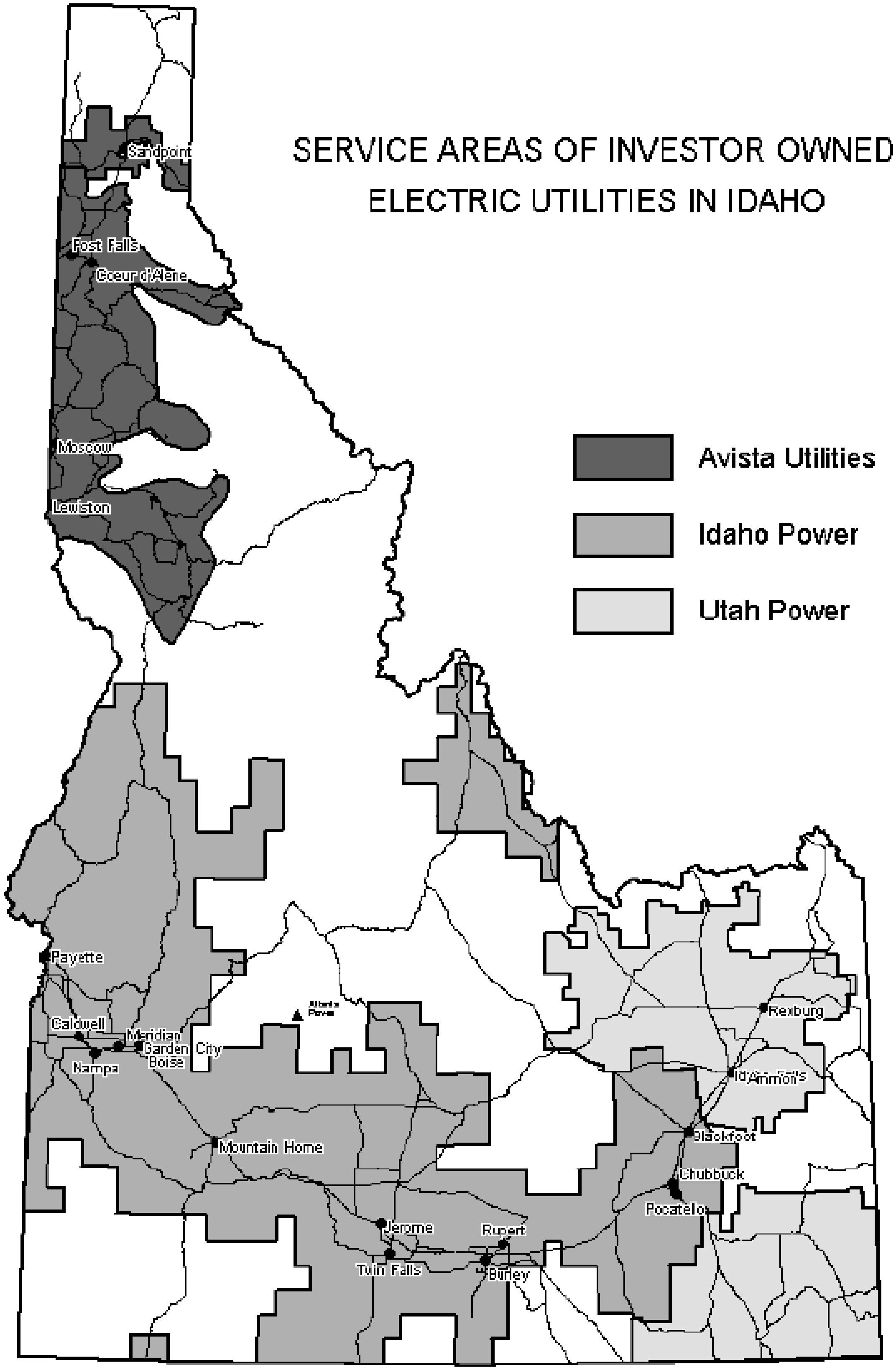
The Commission approved a sales agreement with Idaho Winds LLC for a wind project six miles northwest of Glenns Ferry in Elmore County.

Meridian-based Idaho Winds LLC will construct and operate the 21-megawatt Sawtooth Wind Project. Though its optimum capacity is 21 MW, under normal conditions it will not exceed 10 average megawatts on a monthly basis. The wind project is scheduled to be in operation by Dec. 31, 2012.

The project will operate as a Qualifying Facility under the provisions of PURPA, the Public Utility Regulatory Policies Act of 1978. PURPA requires electric utilities to offer to buy power produced by qualifying small-power producers or co-generators. The rate to be paid project developers, called an "avoided cost rate," is to be equal to the cost the electric utility avoids if it would have had to generate the power itself or purchase it from another source.

Under the 20-year contract, Idaho Power will pay the posted rate of $75.45 per megawatt-hour during months of normal demand in the first full-year of the contract, anticipated to be 2013. Under the agreement, the price gradually increases through the 20-year life of the contract. For example, the 2030 price during normal demand months is $118.97 per MWh. The rates vary during light-load and heavy-load months and hours.

In the same order, the commission accepted a letter agreement between Idaho Power and the Alkali Wind Project that was originally to be built on the same site. Due to a transmission study delay and escalating costs during that delay, the Alkali project was terminated.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