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

2007 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
383,992 Residential Customers/$0.0592
73,726 Commercial Customers/$0.0437
118 Industrial Customers/$0.0291

Avista Utilities

2007 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
101,671 Residential Customers/$0.0691
16,027 Commercial Customers/$0.0669
477 Industrial Customers/$0.0424

2007Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)

PacifiCorp/Rocky Mountain Power

54,656 Residential Customers/$0.0697
7,717 Commercial Customer/$0.0653
5,487 Industrial Customer/$0.0459

Summary of major electric rate cases

Case No. IPC-E-07-08, Order No. 30508
February 28, 2008
Commission approves Idaho Power rate case settlement
The commission adopted a settlement proposed by several parties in the Idaho Power Company rate case that resulted in an average overall 5.2 percent rate increase for customers effective March 1, 2008. For residential customers, the increase was 4.7 percent. Idaho Power requested an overall 10.35 percent increase.

With the increase, the residential non-summer rate increased from 5.4 cents per kWh to 5.7 cents. The summer rate for use beyond 300 kWh increased from 6.1 cents per kWh to 6.4 cents. For an average residential customer using 1,050 kWh per month, an average non-summer monthly bill will increase from $63.60 to $66.36. An average summer bill (June through August) increased from $68.61 to $71.73. Those calculations include the $4 per month customer service charge and the annual Power Cost Adjustment (PCA), which this year is a surcharge of 0.24 cents per kWh. The increase for commercial, industrial and irrigation customers is 5.65 percent.

The settlement did not propose a rate of return or a return on equity, so the commission's order addresses only the amount of revenue granted. The company was granted a $32.1 million increase in annual revenue after requesting $63.9 million.

Idaho Power filed the case in June 2007. It said the increase was necessary to pay for an additional $300 million investment for new and upgraded transmission and distribution facilities, for equipment upgrades and environmental protection measures and for relicensing and equipment investment related to its hydroelectric projects.

Intervenors in the case included the Idaho Irrigation Pumpers Association, the Industrial Customers of Idaho Power, Micron Technology, Inc, the U.S. Department of Energy and Kroger Company. All parties, with the exception of Kroger, signed the settlement. Kroger, which represents the Fred Meyer and Smith's Food King stores in Idaho, generally supported the settlement but wanted large commercial customers like itself to be afforded a Time of Use rate similar to that allowed industrial customers. The order directed Idaho Power to develop a time-of-use rate proposal for large commercial customers and present it to the commission for approval.

The commission ordered that issues not resolved in the case be addressed in future discussions with commission staff and interested parties before the company files its next rate case.

Those issues include:

- deciding on whether to include actual historical financial information during a 12-month “test year” to determine a future rate or whether to use forecasted data. Historically, the commission has approved only the use of historical data or a blend of historical and forecasted data. Idaho Power favors using forecast data, arguing that continued load growth and infrastructure additions during the pendency of a rate case results in the company being already revenue deficient when a new rate is finally implemented. “The company’s test year was a contentious issue,” the order said, with commission staff and most intervenors filing testimony strongly disagreeing with Idaho Power’s test year methodology. The settlement states that parties will participate in good-faith discussions regarding a forecast test year methodology that “balances the auditing concerns. relief.”
- devising a mechanism that will either adjust or replace the current Load Growth Adjustment Rate. The load growth rate is intended to compensate for additional revenues attributable to load growth between rate cases. An amount related to load growth is subtracted from the company’s power supply expenses during the Power Cost Adjustment (PCA) process, resulting in a lower PCA for customers.
- updating Idaho Power’s “Irrigation Peak Rewards Program,” to encourage more participation from irrigators. Currently, only about 10 percent of Idaho Power irrigation customers participate in the program, which gives irrigators financial credits for agreeing to curtail their use during times of peak demand. Irrigators want a larger credit and want to be able to participate in a dispatchable program as well as scheduled curtailments. Under a dispatchable program, Idaho Power could remotely curtail irrigation systems during peak hours. The ability for the company to remotely curtail irrigation demand makes the program more valuable to the company and irrigators.

May 30, 2008

<u>Commission adopts three Idaho Power rate adjustments</u>

State regulators approved several rate adjustments to Idaho Power Co. customer bills that become effective June 1, 2008.

The largest is an increase in the annual Power Cost Adjustment (PCA), which this year is a surcharge that increases rates for all customer classes by an average 10.7 percent. For residential customers, the increase is 8.45 percent.

The commission also approved an increase to base rates of 1.37 percent for $63.4 million in costs for the new Danskin natural gas plant near Mountain Home. There is also a 1 percent increase to the energy efficiency rider to fund an expansion to Idaho

Power's demand-side management (DSM) programs. Finally, rates for residential and small-commercial customers will decrease by eight-tenths of 1 percent as a result of the Fixed Cost Adjustment.

Power Cost Adjustment
IPC-E-08-07, Order No. 30563
Every year on June 1, customer rates are adjusted either up or down to reflect the Idaho Power's annual power supply costs, which vary from year to year depending on changes in Snake River stream flows and the market price of power. Snow pack and river flows from the winter of 2006-07 were below normal and reservoirs were low. In addition, temperatures broke the 100-degree mark 14 times in July alone. Idaho Power's record for customer demand was broken five times before setting an all-time high of 3,193 megawatts on July 13.

Due to lack of hydroelectric generation, Idaho Power had to go to the wholesale market and buy power. It had to fire up its natural gas peaker plants to meet load during those peak-use days. Consequently, the company spent about $163 million buying power and natural gas to serve its customers.

During some years, the PCA is a credit rather than a surcharge. During 2006, customers got an average 16 percent PCA credit. Unlike a change in base rates, which can increase company profits, the annual PCA surcharge or credit does not affect company profits. Revenues collected from the PCA are kept in a deferred account, audited by the commission, and used only to pay power supply and related fuel expenses.

The impact of the PCA was mitigated slightly by a commission decision to apply about $16.5 million in revenue the company earned from its sale of surplus sulfur dioxide emissions credits toward reducing the PCA. Without that, the average PCA increase would have been about 12.8 percent.

The commission denied the Industrial Customers of Idaho Power's request to spread recovery of the power supply expenses over three years. "As stated by the parties in this case, Idaho has experienced unprecedented drought and forecasts for water are, at best, uncertain. It is simply too risky, and potentially compounds the problem, to seek recovery from ratepayers across three future years," the commission said.

The commission said it remains concerned about the increased use of natural gas-fired peaking plants. "In previous orders, the commission has noted concerns with the volatility of natural gas prices. We are also increasingly concerned with the persistent high price of natural gas this year," the commission said. The commission asked the company to provide more information about Idaho Power's daily decisions on whether to run its gas-fired peaker plants to meet demand or to purchase wholesale power.

Danskin power plant
IPC-E-08-01, Order No. 30559
Danskin, part of the Evander Andrews Power Complex near Mountain Home, is a 170-megawatt natural gas plant. Expenses related to plant construction totaled $56.7 million and expenses related to transmission and interconnection upgrades to deliver the power generated from the plant totaled $7.54 million.

A commission staff audit of contract costs and change order costs, as well as transmission and interconnection facilities costs, found them to be reasonably and prudently incurred. About $422,000 in anticipated plant costs were not able to be verified and thus removed from the company's original request.

Costs in this case do not include two components of anticipated transmission upgrades: a new Hubbard substation and a 230 kV transmission line between Danskin and the new substation. These are estimated to cost $19.5 million and may be included in a future rate case.

Energy efficiency rider
IPC-E-08-03
The energy efficiency rider increased from 1.5 percent of base revenue to 2.5 percent. On an average customer bill, the increase is about 78 cents during the non-summer months and about $1 during June, July and August. This will allow Idaho Power to increase funding for conservation and efficiency funding from the current $9 million to $16 million.

The commission approved the rider increase because the company saves more in energy costs than it spends on the programs, benefiting all customers. "We commend the company for increasing its commitment to DSM programs that apparently are actually resulting in energy savings to customers," the commission said. "Even if the company's DSM program costs increase, all cost-effective DSM programs will delay the need to construct new, costly generating facilities."

Demand response programs are designed to reduce the actual megawatts the company needs at specific times of the day and year when electricity is in short supply and at high cost. Through the use of load control devices installed on customer meters, Idaho Power can reduce the amount of power it needs during peak periods when electricity is most expensive. Idaho Power was able to shave 57 megawatts off peak demand during 2007. One megawatt is enough to power about 700 average-sized homes during the non-summer months and 350 average-sized homes during summer.

The surcharge also funds energy efficiency programs that reduce megawatt-hours consumed. These programs include cash incentives and information and services that aid in the construction of energy-efficient buildings and installation of energy-efficient appliances. During 2007, Idaho Power was able to reduce consumption by 91,145 megawatt-hours through energy efficiency programs.

Several organizations supported an increase in the rider including the Northwest Energy Coalition, the Renewable Northwest Project, the Idaho Conservation League and the Snake River Alliance.

The commission declined to approve Idaho Power's request to allow rider funds to be used for small-scale renewable projects, such as photovoltaic systems. The commission said it would need more information about the projects and their costs before allowing already limited rider funds to be directed toward them.

Fixed Cost Adjustment
IPC-E-08-04, Order No. 30556
To encourage utility investment in conservation, the commission, in 2007, authorized a three-year pilot program called the Fixed Cost Adjustment (FCA). The rationale for the FCA is that utilities aren't encouraged to promote energy efficiency among its customers when the company recovers its costs primarily though energy sales.

The FCA allows the company to recover costs through a surcharge if it under-collects fixed costs because of reduced electrical use. Conversely, if the company over-collects fixed costs, customers get a credit instead of a surcharge.

During 2007, the company claimed it over-collected $3.5 million from residential customers and under-collected $1.2 million from small-commercial customers. Thus, it proposed a 1.17 percent monthly rate credit for residential customers and a 3 percent monthly surcharge for small-commercial customers. Recovery of the full amount from small-commercial customers would require a 7.3 percent surcharge, but part of the FCA pilot program is a 3 percent cap on any increase.

Commission staff, however, said it could not endorse Idaho Power's fixed cost assumptions, largely because fixed costs per customer class were not established in the company's last rate case. Until a future rate case can more firmly verify fixed costs, the commission adopted the commission staff's proposal to split the net $2.4 million deferral balance (the $3.5 million over-collection for residential customers minus the $1.2 million under-collection for small-commercial) to both customer classes. The result is an approximate 0.8 percent rate decrease for both customer classes.

Case Nos. AVU-E-08-01, AVU-G-08-01 (General electric and gas rate cases)
Case Nos. AVU-E-08-05, AVU-G-08-03 (Annual power cost and gas cost surcharges)
October 1, 2008
Avista rate increases and surcharges effective Oct. 1

The commission approved a negotiated settlement that increased base rates for Avista Utilities' electric and gas customers. Also authorized was an increase to two yearly surcharges to pay for increasing gas and electric supply costs.

In the base rate case, the commission approved a settlement, negotiated by four major parties, that allows Avista to increase its annual revenue for electric service by $23.2 million, or 11.98 percent. For the average Avista residential customer who uses about 977 kilowatt-hours per month, the increase is $7.89 per month.

The settlement resulted in a $9.1 million reduction from the company's original request of $32.3 million in increased annual revenue, which would have meant an average 16.7 percent rate increase.

On the gas side, the commission approved the settlement's proposal of an annual increase of $3.9 million or 4.7 percent. For the average Avista residential customer who uses 65 therms per month, the increase to permanent base rates is about $4.03. Avista originally requested an increase of $4.7 million in annual revenue or 5.8 percent.

This was the first Avista general rate case since 2004. However, it came on top of Avista's annual Power Cost Adjustment (PCA) and Purchased Gas Cost Adjustment (PGA), both adjusted annually on Oct. 1.

The PCA is an increase from the current surcharge of 0.267 cents per kWh to 0.61 cents. For the average residential customer, that's a monthly increase of about $3.43.

The PGA is about a 4 percent increase, or $2.96 per month for the average residential customer. When Avista originally filed its gas cost surcharge on Aug. 18, 2008, it requested a 14.2 percent increase in the surcharge. But declining wholesale gas prices since then and the company's ability to purchase additional natural gas for the coming year resulted in the company adjusting its filing on Sept. 15 from 14.2 percent to 4 percent.

The commission noted the impact the permanent rate increase and the electric and gas surcharges have on all customers, particularly those on fixed and low incomes. "This commission is not oblivious to the consequences of its rate orders," the commission said. "The volatility in the energy markets, however, shows no sign of abating."

In response to rising gas and electric prices, which are occurring nationwide, the commission adopted the rate case settlement proposal to increase funding for low-income weatherization and authorized funding for low-income outreach and conservation education. It also ordered Avista, and other Idaho regulated utilities, to participate in upcoming energy affordability workshops. As part of this process, Avista has agreed to attempt creation of a low-income rate assistance program for its Idaho customers.

Unlike an increase to permanent base rates, the electric and gas cost adjustment surcharges are one-year adjustments that track the variable costs of energy and gas supply. The PCA and PGA are impacted primarily by wholesale market costs for electricity and for natural gas and, on the electric side, by reduced hydro generation due to less snowpack. During years when wholesale market prices are lower than normal and hydro conditions are normal, customers can get a credit rather than a surcharge. In 2006 and 2007, Avista customers received PGA reductions. Also, unlike a permanent base rate change, increased revenue from the PCA and PGA can not increase profits. They can be applied only toward meeting Avista's power and gas supply expenses.

Some Avista customers filed written comments protesting the surcharge increases as a means to enhance the company's profits or the salaries of executives. "We assure customers that neither the company's corporate profits nor executive salaries are included in or increased" by the power and gas supply surcharges, the commission said. "It is not possible for us to just say 'no' to increases that have been shown to be necessary to maintain a utility's financial health. To do so would violate the law."

In both the permanent rate case and in the electric and gas cost adjustment cases, customers responded to a newspaper article that reported a 72 percent increase in profits for Avista from the second quarter of 2007 to the second quarter of 2008.

The commission said the figure is misleading. During the second quarter of 2007 the company recorded the sale of Avista Energy, an affiliate of Avista Utilities, at a loss of $12 million. Even though customers did not have to pay for that loss, Avista Energy, at the time, was part of Avista Corporation, thus the loss was included in the company's quarterly earnings report, reflecting an abnormally low second quarter of 2007. In 2008, earnings were closer to normal. During 2007, Avista still failed to realize the overall rate of return authorized by the commission. In this case, the commission established an allowed rate of return of 8.45 percent for Avista and a return on equity of 10.2 percent.

Customers also responded to a newspaper report that listed compensation for the top five Avista executives at about $3.6 million. While base salaries are included in rates, bonuses and other cash incentives for executives are paid by shareholders. In this settlement, the annual rate compensation for the top five executives is $1.45 million. While still seemingly high, commission staff noted that if compensation for Avista's top 12 executives was entirely eliminated the reduction for customers would be 0.5 percent.

Parties to the settlement included the commission staff, which is obligated to represent the interests of all customer classes. Other parties included Avista, Potlatch, and the Community Action Partnership Association of Idaho (CAPAI), which represents primarily low-income customers.

CAPAI was instrumental in securing an increase of $115,000 per year – from $350,000 to $465,000 – for weatherization projects for homes of low-income customers. Currently only 10 percent of homes receiving funds under the federal Low Income Heating and Energy Assistance Program (LIHEAP) are weatherized. In addition, the settlement allocates $25,000 for community action agency personnel to assist in low-income outreach and conservation education.

"Opportunity for near-term relief for customers … lies in their ability to enact energy efficiency and conservation measures and reduce their energy demand," the commission said.

The permanent rate increase is to meet significant increases in fuel costs as well as increased costs Avista incurred to purchase power it needs to meet growing customer demand. Avista also invested in upgrades to aging infrastructure to increase capacity and reliability. Those investments include upgrades to the Noxon Rapids and Cabinet Gorge hydroelectric projects and the Colstrip thermal project. The company spent more than $130 million to upgrade its electric transmission system.

On the gas side, $3 million of the $3.9 million increase in annual revenue will go toward the acquisition of the Jackson Prairie Natural Gas Storage Facility and the installation of automated meters. The additional storage is designed to allow Avista to purchase gas supply when costs are down and store it for use during heavy demand months when gas costs are higher. That should result in lower purchased gas costs adjustments in future years. The automated meters will provide savings in meter reading and customer service expense in addition to allowing for time-of-use pricing which can result in shifting use away from peak-use periods when prices are higher.

Case No. PAC-E-08-07
Oct. 8, 2008
Commission opens docket in Rocky Mountain case

Rocky Mountain Power, which has about 70,000 customers in eastern Idaho, filed an application with the commission on Sept. 19, seeking an annual increase in revenue of $5.9 million, or about 4 percent.

If the commission were to grant Rocky Mountain's request in its entirety, the bill for an average residential customer who uses 850 kilowatt-hours per month would increase by

$3.55 per month, or 4.73 percent. The company is requesting a 2.31 percent increase for irrigators, no increase for small commercial customers and a 7.96 percent increase for large commercial customers.

Rocky Mountain claims that as demand for electricity has grown, it has made investments in new infrastructure and facilities in its territory which includes much of Utah, eastern Idaho and western Wyoming. The company expects to spend $2 billion annually over the next 20 years on new plant investment including new generation resources, transmission lines and distribution facilities needed to meet customer demand. In addition, the company asserts that the cost for fuel the company must acquire to serve customers – such as natural gas – has also increased.

Rocky Mountain Power claims that an overall revenue requirement of $19.4 million is needed for the company to earn the return on equity of 10.75 percent the company is requesting. However, caps placed on Rocky Mountain by previous agreements, including one with its large industrial customers, Monsanto and Agrium, reduces the request from Rocky Mountain Power to $5.9 million.

Case No. ATL-E-08-02, Order No. 30578
June 30, 2008
Commission approves emergency surcharge for Atlanta Power

The commission approved a 33.6 percent emergency surcharge for the customers of Atlanta Power Company effective July 1. The company had requested a 54.2 percent emergency surcharge on top of a 60.6 percent increase in base electric rates.

The emergency surcharge is to pay for expenses related to the failure of the utility's hydroelectric turbine last August. In March, the commission authorized the company to incur a debt of $110,000 for expenses associated with turbine repair, the purchase of a stand-by diesel generator and other minor expenses.

The commission approved recovery of that loan with the accompanying carrying charges, but it ordered the company to maintain a separate record of surcharge payments so that it may review the surcharge and the reasonableness of the interest rate during the upcoming rate case. The surcharge is subject to refund.

The commission denied inclusion of an $18,808 loan to the company owner in the emergency surcharge. Instead, the commission said it would address that issue in the upcoming general rate case. The commission also deferred to the rate case the issue of whether two customers, the company's owner and the home of two onsite employees, should continue to receive electric power at no cost as part of their compensation package.

Atlanta Power serves about 75 residential and commercial customers in the Elmore County community of Atlanta.

Other electric news

September 25, 2008
PUC critical of BPA decision that reduces or eliminates customer credits

A Bonneville Power Administration decision to eliminate or radically reduce electric rate credits to 85 percent of residential and small-farm electric customers in Idaho is "unacceptable," according to state regulators.

The Idaho Public Utilities Commission said today it "will pursue all available legal remedies to address this punitive and egregious error."

The Northwest Power Act, enacted in 1980, allows residential and small-farm electric customers in the Northwest to share in the benefits of the region's federal hydroelectric projects through one of two ways. Customers of publicly owned utilities, such as rural electric co-ops and municipalities, benefit with preferential access to low-cost federal power available from BPA. Customers of the region's investor-owned utilities – which represent about 85 percent of Idaho customers – receive their share of the benefit through a financial credit on the bills of residential and small-farm customers through the Residential Exchange Program (REP). Residential and small-farm customers of Rocky Mountain Power in eastern Idaho, of Avista Utilities in northern Idaho and of Idaho Power across southern Idaho have received REP credits since 2001.

In May of 2007, the Ninth Circuit Court of Appeals declared that BPA, the region's federal wholesale power marketer, did not act in accordance with the Northwest Power Act when it approved a settlement in 2000 regarding wholesale power rates and REP credits to customers of public and private utilities in the Northwest. The court said customers of the region's investor-owned (private) utilities received too much in credits while customers of public co-ops and municipalities were overcharged.

Shortly after that decision, BPA suspended the credit for all of Idaho's three major investor-owned utilities until BPA could re-calculate the rates and credits to comply with the court's directive. The temporary suspension of the credit resulted in an almost immediate 9.5 percent increase in June of 2007 for Idaho Power and Avista residential and small-farm customers. The impact was even more severe for Rocky Mountain

Power in eastern Idaho, where the loss of the credit meant a 28 percent increase for residential customers and a 51 percent increase for irrigation customers.

BPA established new power rates and REP credits that essentially eliminated the credit for customers of Idaho Power and Rocky Mountain Power and greatly reduced it for Idaho customers of Avista Utilities. The credit for Avista customers was reduced from $3.5 million to $1 million. The credit was reduced to zero for customers of Idaho Power (from $15 million) and for customers of Rocky Mountain Power (from $10.7 million).

The biggest factor in the almost total elimination of the credit is BPA's decision to require future customers in the region to repay $767 million in benefits that have already been credited customers in the past. Further, BPA opted to shorten the pay-back period from a previously stated 20-year time frame to just seven years.

"The Northwest Power Act envisioned Residential Exchange Program benefits for all four states – Idaho, Montana, Washington, and Oregon. For the BPA administrator to issue a decision that all but eliminates these benefits for Idaho customers is inconsistent with the act." the commission said. "The act does not say that the benefits are available in the other three states, but not in Idaho."

The amount of the credit is determined by formulas using various factors, including a utility's average system cost for producing power. In essence, if an investor-owned utility's average system cost to produce electricity results in rates higher than those offered to public utility customers served by BPA, a financial credit can be obtained through BPA that lowers investor-owned utility rates.

However, in an action that the Idaho commission says has "no bearing in the plain language of the Northwest Power Act," BPA is claiming that Idaho Power and Avista owe it money because their average system costs for many years allowed lower rates for their customers than BPA's rate to customers of publicly owned utilities. BPA calculated that Idaho Power owes more than $250 million and Avista owes more than $100 million. BPA decided these amounts must be repaid before either company receives REP credits. It will take Idaho Power more than 20 years to repay BPA, thereby denying credits to Idaho Power's residential and small-farm customers for at least a generation.

The BPA is a not-for-profit federal agency that markets power from 31 federal hydroelectric dams and a nuclear plant in the Northwest. The agency accounts for about 40 percent of the electricity consumed in the region, selling to about 140 utilities in Washington, Oregon, Idaho and Montana.

Case No. AVU-E-07-08
March 25, 2008
Avista counts on natural gas, not coal, to meet future resource needs

The Idaho Public Utilities Commission has accepted a long-range plan for Avista Utilities that depends more on natural gas for its future energy resources, rather than coal.

The Integrated Resource Plan (IRP) outlines how Avista intends to meet the demands of its growing customer base over the next decade. Avista, which serves about 115,000 customers in northern Idaho, says it will need 350 megawatts from natural gas sources to meet customer demand. It plans on getting most of that – 275 MW – from the Lancaster Generation Facility near Rathdrum. Avista also plans on adding 300 megawatts from wind sources, 35 MW from other renewable resources and 87 MW from energy savings due to conservation measures.

Without the additional generation, the company states it would face generation shortfalls of about 83 average-megawatts in 2011 and 272 aMW by 2017.

Avista decided to drop plans outlined in an earlier 2005 IRP for coal-fired generation for several reasons including legislation in Washington state where the utility has most of its customers. Washington enacted a greenhouse gas emissions standard that precludes Avista from acquiring a new pulverized coal plant or entering into a long-term contract with an existing plant.

Several utilities have dropped coal sources from their long-range planning due to new emissions standards and higher costs associated with the potential for carbon taxes, making coal less competitive with other generation alternatives.

Avista's 2007 plan also includes fewer renewables – from 500 megawatts to 350 MW – than it had hoped for in its 2005 plan. Avista said the cost of wind resources has increased by more than 100 percent over the last six years. Legislation in Oregon, Washington and other states that mandates a certain percentage of generation from renewable sources has increased the demand for wind turbines. That demand reduces their availability and increases their price.

"Ironically, Idaho presently has neither carbon emission standards nor renewable portfolio standards, yet the new legislation in other states has effectively limited the new generation choices for serving Idaho loads," commission staff said. Utilities in Idaho that serve several states must meet the requirements in all the states they serve. It is "impractical to develop new generation projects devoted solely to serve Idaho loads," commission staff said.

Avista moved away from natural gas-fired sources in 2005 because of the price volatility in natural gas markets that drastically increased prices between 2003 and 2005. But with the elimination of coal-fired generation and the higher cost of renewables, the utility returns to natural gas to meet some of its future demand.

Commission staff urged Avista to develop new and innovative methods to counteract natural gas price volatility and to maximize the use of cost-effective load control programs. Further, staff said utilities should "dutifully consider the potential for integrating nuclear energy into their long-term resource planning."

Avista is planning an additional 87 MW from conservation measures, an 85 percent increase in conservation since Avista's 2003 IRP and a 25 percent increase over the 2005 IRP.

Case No. IPC-E-07-18, Order No. 30529
April 16, 2008
Commission applies emission sales proceeds against PCA

The commission determined that nearly all of the proceeds Idaho Power Company earned through its sale of sulfur dioxide (SO_2) emissions credits should go toward offsetting the company's proposed Power Cost Adjustment surcharge.

On April 15, Idaho Power filed its annual Power Cost Adjustment, requesting a one-year surcharge to recover $87 million in power supply and fuel expenses. To recover the full $87 million, Idaho Power would need to raise rates about 12.7 percent for one year effective June 1. The order issued by the commission regarding how proceeds from SO_2 sales should be used, will reduce that $87 million to about $71 million, resulting in less of an increase in the proposed PCA surcharge.

Idaho Power sold 35,000 SO_2 allowances during 2007 for $19.6 million less brokerage fees. The company proposed several ways of using revenues from the emissions sales to benefit customers including 1) buying green tags from owners of small-wind projects or other renewable projects; 2) allowing Idaho Power to enter negotiations or solicit bids to buy a wind project's development rights; 3) using $500,000 to develop classroom education programs about energy efficiency with the remaining balance directed toward other energy efficiency operations; and 4) applying the proceeds against the PCA to provide rate relief to customers.

The commission conducted workshops and solicited public comment on the best use of the SO_2 proceeds. Micron, the Industrial Customers of Idaho Power and PUC staff all endorsed using the revenues to offset the PCA. The Idaho Conservation League and wind developers Ridgeline Energy and Windland endorsed buying the rights of a wind project. The Snake River Alliance supported the funding of energy education programs and well as investment in renewable projects and energy efficiency programs.

The commission agreed to set aside $500,000 of the proceeds to be directed toward energy education as proposed by the Idaho Energy Education Project. However, before authorizing the money, the commission wants more specifics about the program such as a syllabus, curriculum or more details about existing programs with school districts or state agencies.

The commission commended Idaho Power and other participants for the variety of proposals. “We, too, believe that it is beneficial to ‘think outside the box’ and consider non-traditional uses of one-time revenues,” the commission said. However, the commission felt customers would most benefit by applying the proceeds against this year’s PCA deferral balance, one of the highest on record.

An amendment to the 1990 Clean Air Act establishes 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.

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 more than 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.

Idaho Power has an ownership interest in three coal-fired plants: Jim Bridger in Wyoming, North Valmy in Nevada and Boardman in Oregon.

Case No. AVU-E-07-09, Order No. 30603
August 8, 2008
Commission allows remote disconnect pilot program

The commission gave Avista Utilities the go-ahead to implement a pilot program that will allow it to disconnect and reconnect customers from a remote location. Under the 18-month pilot, Avista will be allowed to install up to 600 remote disconnect collars that allow for the remote enabling and disabling of service from Avista’s offices.

Customers selected for the program would include those who have threatened to harm Avista employees or property, who live on a property where there is danger from animals or has obstructed access to meters and those who have had two field collection visits or disconnections in the preceding 12 months, meaning that upon the third visit a remote collar could be installed.

Avista claims the program will reduce operating and maintenance expenses related to multiple disconnection and reconnections, increase the productivity of its employees by eliminating multiple trips to customer homes for collections, enhance employee safety, establish a quicker response time to reconnect service and recognize a reduction in bill defaults and write-offs by encouraging prompt consumer payment over time.

Avista’s application was accepted by the commission only after revisions proposed by commission staff as well as groups who originally opposed the plan, including AARP Idaho and the Community Action Partnership Association of Idaho.

Those revisions included adding a provision that customers who are receiving assistance from Avista’s CARES program would be excluded from remote disconnection. Other commission rules that protect qualifying customers from disconnection during the winter months would still apply. The revisions also clarified that remote disconnection can happen only upon the third field collection visit or disconnection within a preceding 12-month period. Further, the revisions also required that Avista consult with commission staff regarding the language to be placed on the door hangar envelopes when leaving a Notice of Disconnection on a customer’s property.

An advantage of the program, commission staff said, is that power can be restored to a disconnected customer within minutes any time during the day or night and even on weekends. Under the current method, it can take several hours before a utility employee can schedule a home visit to restore power.

Avista and all regulated utilities must abide by the commission’s customer service rules regarding disconnection. A first disconnection notice is sent at least seven days before the proposed disconnection date. A second notice is sent at least three days before disconnect. Then a call must be made to the customer at least 24 hours before disconnection. Under the pilot, Avista plans to continue providing written and oral notices. The only rules waived under the pilot is one requiring a utility employee to knock on the customer door to provide a final opportunity to make a payment and another that requires the employee to give to the customer or leave in a conspicuous location a notice showing the grounds for termination and steps to be for reconnection.

Case No. IPC-E-08-13, Order No. 30613
August 14, 2008
PUC accepts power purchase agreement between Idaho Power, Montana provider

The commission approved an Idaho Power Co. contract to buy 83 megawatts per hour from a Montana energy provider during heavy load hours in the months of June, July and August beginning in 2010.

The two-year power purchase agreement is with PPL EnergyPlus, LLC, the marketing arm of PPL Montana. (PPL Montana acquired most of the generating assets sold by the former Montana Power Company when the state of Montana deregulated its electric utility industry several years ago.) The agreement with EnergyPlus replaces an Idaho Power/PPL Montana contract that expires at the end of August 2009. The agreement is effective June 1 through Aug. 31, 2010, and June 1 through Aug. 31, 2011, providing electricity for 16 hours, six days a week, Monday through Saturday.

Idaho Power issued a request for bids to replace the expiring PPL Montana contract and EnergyPlus was the successful bidder. The price to be paid for the energy is $92.95 per MWh. In addition to the energy price, Idaho Power will buy firm monthly transmission services across Northwestern Energy's transmission system in Montana to Idaho Power's Jefferson delivery point near the Montana-Idaho border. That moves the total price, including energy and transmission, to $101 per MWh.

The price is fair and reasonable when compared to other possible sources, the commission said, but noted that there is good reason to limit the contract for two years, given fluctuating prices. "We find it reasonable to conclude that without the purchase, the company will not have sufficient resources to meet its summer peak load requirements for those years," the commission said.

Contracting with EnergyPlus is also advantageous, Idaho Power maintains, because of existing transmission constraints on the west side of Idaho Power's system, which makes power purchases on the east side preferable.

Case No. PAC-E-08-03, Order No. 30657
October 10, 2008
PacifiCorp gets certificate for eastern Idaho transmission line

The commission approved PacifiCorp's application to add to its Idaho certificate in order to build a transmission line to send power from remote wind sites in Wyoming and Idaho to urban load centers.

The 345-kilovolt transmission line will extend from an existing substation southwest of the Salt Lake City airport north to a new substation at Downey. In Idaho, the line extends through Bannock and Oneida counties.

Cost of the project is $750 million, but only about 3 percent of that is allocated to Idaho customers in PacifiCorp's six-state territory.

The commission received about 34 customer comments, most from customers who did not approve of the location of the Downey substation or the alignment of the transmission line. The Idaho commission does not have the authority to choose the location or the alignment of transmission projects. Those decisions are made by local planning and zoning commissions, city councils and county commissions. The commission's role is to determine if the project is necessary to meet customer demand and if the project does not interfere with the transmission lines or plants of another public utility. The need for the line was not refuted in customer comments.

The commission's order said PacifiCorp's application satisfies the requirements outlined in Idaho statutes. "Thus, we approve PacifiCorp's application. … In doing so, the commission emphasizes that this order does not approve any particular siting or alignment – that is primarily a responsibility of local government."

The commission did say that the company should have involved local government officials and citizens earlier in the process. "Soliciting public input during the early planning stages of such a large-scale transmission project could go a long way toward satisfying or alleviating some of the questions and concerns which inevitably arise surrounding the alignment and siting of transmission line on private property."

PacifiCorp sponsored open houses to address community concerns and re-aligned an Idaho section of the project from an original alignment to address citizen complaints.

In a 2007 planning document filed with the Idaho commission, PacifiCorp said it intended to acquire additional transmission capacity to accommodate current and planned generation projects that can provide an additional 2000 megawatts of renewable energy to customers. Most of that energy will come from remote wind projects in Wyoming and Idaho. "It is a reality that a majority of viable wind projects are located some distance from the metropolitan areas that often represent an electric utility's primary load centers," the commission said.

This project is designed to enhance energy delivery and reliability between PacifiCorp's eastern control area (Wyoming, eastern Idaho and Utah) and its western control area (Oregon, Washington and northern California).

October 2, 2008
Case No. GNR-U-08-01
Commission opens case to address energy affordability

Idaho's regulated utilities, as well as customers and groups representing customers, are being directed by state regulators to participate in workshops designed to find methods to make energy more affordable for consumers.

The Idaho Public Utilities Commission is ordering its staff to conduct the workshops and directing Idaho Power Co., Rocky Mountain Power, Avista Utilities and Intermountain Gas to participate.

The commission's order says the following:

> *"The Commission recognizes that there are a variety of factors contributing to significant upward pressure on electric and natural gas rates in Idaho and energy affordability has become a central issue for many Idaho households and businesses. Utilities are facing the prospect of more customers being unable to pay their energy bills in full and/or on time. Customers who are unemployed, have lower incomes, and/or have fixed incomes that fail to keep pace with inflation are disproportionately affected by rising energy costs, since they must devote an increasingly large of their income to paying for natural gas and electricity."*

The commission is hoping that the result of the workshops will be the identification of new programs, policies and/or legislation, procedures and/or resources that could be implemented to make energy more affordable.

Some of the issues that could be addressed at the workshops include 1) bill mitigation (payment plans); 2) bill payment assistance; 3) bill reduction through conservation, weatherization, discounts, reduced rates and tiered rates; 4) reduction in customer costs such as payment transaction costs; 5) removal of barriers to obtaining or retaining service; and 6) case management, such as one-on-one customer assistance.

Wind issues

February 21, 2008
IPC-E-07-03, Order 30488; AVU-E-07-02, Order 30500; PAC-E-07-07, Order 30497
Three-year wind integration case resolved

After nearly three years of deliberation between Idaho's regulated utilities, wind developers and state regulators, three major cases involving how much it costs to add wind to utilities' transmission grids have finally been resolved.

Three orders issued by the commission establish the amount of discounts utilities can assess against wind developers to account for the cost of integrating wind into their systems. The orders also remove a cap on the size of small-power projects that can qualify for a rate published by the commission. Also removed is a provision that allowed utilities to pay wind developers a market rate rather than the typically higher state rate when wind output from projects did not fall within forecasted ranges.

"The commission finds that the costs of wind integration are real, not illusory," the commission said. The commission said the integration charges "will provide long-term stability" for small-wind development and will "provide flexibility to protect customers from published rates that are too high."

Due to a rapid increase in the number of small-wind projects seeking access to its transmission grid, Idaho Power Co. in 2005 asked the commission to suspend small-power wind development to allow it time to study how much it costs the to provide back-up generation when wind output is less than projected. The commission denied the suspension, but agreed to decrease the size of small-power projects – from 10 megawatts to 100 kilowatts – that could qualify for the published rates that utilities must pay generators of small renewable power projects.

Since then, Idaho Power Co., as well as Idaho's two other major electric utilities Avista Corporation and PacifiCorp, completed studies to determine wind integration costs. The utilities and most wind developers proposed a settlement that would bring the size limit of projects that qualify for the small-power rate back up to 10 MW. Further, wind developers proposed to provide more certainty to utilities by agreeing to participate in the cost of acquiring state-of-the-art wind forecasting services and, further, provide guarantees that their projects would be mechanically able to generate at full output during 85 percent of the hours during a month. In exchange for those agreements by wind developers, utilities agreed to support removal of the "90/110 performance band" which required that when output was less than 90 percent of projections or more than 110 percent of projections, utilities could pay developers the usually smaller market-based rate rather than the published rate.

The only issue the parties could not agree upon was the size of the discount or, in the case of Exergy Development Group of Idaho, whether there should be a discount at all. With the parties unable to agree on that issue, the matter was brought before the commission for a decision.

Idaho Power Co. had originally proposed that it be allowed to discount $10.72 per megawatt-hour from the cost it paid small-wind developers. Later, it revised that discount to $7.92.

The commission's order establishes a tiered-discount for Idaho Power and Avista that increases as more wind is added, but caps the discount so that it can go no higher than $6.50 per MWh. For the first 300 megawatts of wind on a utility's system, the discount is 7 percent. That increases to 8 percent when a utility has contracts for 301 to 500 MW of wind and to 9 percent for 501 MW or more.

For example, the discount applied to wind generators who sign a 20-year contract this year with Idaho Power Co. is $5.49 per MWh. For contracts signed this year, Idaho Power is already at the 8 percent tier because it has more than 300 MW of wind contracted to go online. (Wind developers who contracted before the utility reached 300 MW will qualify for the 7 percent discount.) A wind developer who signs a contract this year would be paid $63.17 per MWh, 8 percent less than the published rate of $68.66 per MWh. (Those amounts vary during heavy-load hours and heavy-load seasons.) For a 20-year contract signed this year in Avista's territory, the rate without the discount is $58.25 per MWh during lighter-use months and $74.89 during heavier-use months. With the 7 percent discount factored in, Avista would pay wind developers $54.17 per MWh during light-use months and $69.65 per MWh during high-use months.

The commission approved a flat discount rate of $5.10 for PacifiCorp. Wind integration costs can be lower in areas where there is greater geographic diversity and larger control areas, as is the case with PacifiCorp, which operates in six states and is more dependent on thermal generation. Idaho Power and Avista are more dependent on hydroelectric generation.

One wind developer, Exergy Development Group of Idaho, argued against an integration discount saying the science is in its "infancy," and that enough variables and uncertainties exist to make it impossible to determine a fair rate. To avoid integration costs that are inequitable, the commission is requiring all three utilities to participate in workshops to continually update integration analyses and regularly report to the commission. Idaho Power and Avista must report to the commission when its tiered discount percentage increases. Further, developers can petition the commission at any time they believe wind integration costs are outdated or inaccurate.

January 4, 2008
Case No. IPC-E-07-15, Order No. 30480 January 4, 2008
PUC modifies method to calculate rates paid small-power developers

Beginning Jan. 1, 2008, the amount utilities must pay small-power producers under provisions of the federal PURPA act will be calculated under a different formula that is a compromise to an alternative proposed by Idaho Power Co. and the view of wind advocates that the formula should be left alone.

The federal Public Utility Regulatory Policies Act of 1978 (PURPA) requires regulated electric utilities to buy power from qualifying generators of renewable power at a rate determined by state utility commissions. The Idaho commission determines that rate, which is called an "avoided-cost rate." Ideally, 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 September, Idaho Power Co. petitioned the commission to modify the method it uses to calculate the fuel component of the avoided-cost rate. The fuel component, which accounts for more than half of the total avoided-cost rate, varies as wholesale prices for natural gas fluctuate.

The fuel component was determined by using a 20-year forecast of natural gas prices issued by the Northwest Power and Conservation Council (NWPC). The PUC averaged the first three years of that forecast and also included a fixed 20-year escalation rate.

Idaho Power maintained that by using an average of the first three years of the NWPC forecast and a fixed escalation rate over 20 years, the downward trend in natural gas prices forecast in future years is not taken into account. The result is a rate that is higher than avoided cost, Idaho Power contended. A rate higher than avoided cost negatively impacts customers because costs for PURPA contracts are passed on to customers.

Idaho Power proposed using an average of the entire 20-year forecast and eliminating the escalation rate. Under Idaho Power's proposal, a small-power producer who signed a 20-year contract in 2007 would be paid $67.77 per MWh, compared to $72.22 per MWh under the commission's formula.

Wind groups and developers argued the formula should not be changed because Idaho Power's proposed method has never been tested. Wind developers said the commission should adopt a reasonable methodology that produces the best rate for wind developers to restart PURPA development here and put renewable projects at the top of the list of new generation in Idaho. Idaho Power said establishing an avoided-cost rate to make wind projects profitable and stimulate PURPA wind industry is inconsistent with the letter and spirit of PURPA.

The commission ultimately adopted a proposal offered by commission staff and supported by Avista Utilities and Rocky Mountain Power to use each year of the council's 20-year forecast "as is", rather than an escalated average of the first three years. Under that method, a 2007 contract would result in a payment of $66.88 per MWh, compared to Idaho Power's formula, which results in a $67.77 per MWh payment to developers.

February 5, 2008
Case No. IPC-E-07-13, Order No. 30493
Commission says deposits needed from wind developers

The commission has ruled that a wind developer is required to pay deposits to Idaho Power Co. if it wants its five Magic Valley area wind projects to remain in line to interconnect with Idaho Power's transmission grid.

Exergy Development Group and Idaho Power have entered into sales agreements that will permit Exergy to sell all the output from five wind projects to Idaho Power. In a compliaint filed last July, Exergy claimed Idaho Power was improperly seeking another $255,000 in deposits from the projects as a precondition to providing estimates on how much it will cost Exergy to interconnect with Idaho Power's transmission grid. Exergy alleged that a requirement for the deposits is not specified in the company's Schedule 72, the tariff schedule that spells out requirements for interconnecting wind and other small-power projects to Idaho Power's transmission system.

Idaho Power claimed it needs the deposits before it can proceed with three phases of interconnection cost studies. The utility said it has routinely collected deposits from the more than 200 requests for interconnection it has received since 2000. The deposits are needed, Idaho Power claimed, to offset engineering and design expense and to protect customers in case a developer decides to abandon its generation project midstream.

Exergy has paid about $45,000 in deposits thus far for the five projects, which include Golden Valley, Milner Dam, Notch Butte, Lava Beds and Salmon Falls.

Exergy claimed that Idaho Power's insistence on the deposits is based on Federal Energy Regulatory Commission (FERC) rules that govern wholesale wheeling of power across state lines and not on the company's own Schedule 72 tariff. Idaho Power said it incorporated the FERC interconnection rules along with Schedule 72 requirements to ensure fair and consistent treatment to all generators and that doing so does not violate state rules.

In its order, the commission said Idaho Power's use of FERC rules as an internal template for small-power interconnection requests is not inconsistent with Schedule 72. In fact, the commission said, the FERC process encourages renewable development because small-power generators are able to make deposits incrementally as the interconnection studies proceed rather than having to pay the full amount upfront.

However, the commission said Idaho Power should propose additional language to Schedule 72 that describes in detail the three-step study process to interconnection in order to ensure "greater transparency in its interconnection processes."

Conservation, energy efficiency

May 5, 2008
Case No. PAC-E-08-01, Order No. 30543
Commission: Customers will benefit from increase in efficiency rider

Customers of Rocky Mountain Power in eastern Idaho will pay more for a rider on customer bills to fund an expansion of the utility's energy efficiency programs. The increase in the rider, from 1.5 percent to 3.72 percent, is about $1.56 per month more for an average residential customer.

The commission approved the increase as one that will be financially beneficial to customers in the long-term. "We find that demand-side management, conservation, and energy efficiency measures continue to be the least-cost resources that utilities can acquire to serve new load," the commission said.

PacifiCorp, the parent company of Rocky Mountain Power, anticipates a shortage of energy resources to serve peak loads this summer. By implementing programs funded by the rider, the company estimates it will save 13,140 megawatt-hours per year. At the former 1.5 percent, the rider funded programs that saved 8,000 MWh during 2007.

While those customers who directly participate in the conservation programs will benefit the most, "all customers, including those with fixed and limited income, will benefit from deferring the cost of new supply-side resources," the commission said. Further, Idaho's share of system supply costs in PacifiCorp's six-state territory will decrease from expanded conservation programs.

Revenue collected from the rider must go directly to fund and administer energy efficiency programs and cannot be used for other purposes. The enhanced energy efficiency programs will offer information, services and cash incentives to help customers install energy efficient equipment or make permanent operational changes to reduce consumption and save money.

The commission directed the company to file a report each year on May 1 outlining the programs and demonstrating their cost-effectiveness. The commission also directed the company to provide the information necessary to conduct a prudency review of the costs and expenses related to the program during the company's next general rate case. "Costs imprudently incurred will not be paid by customers," the commission said.

The Northwest Energy Coalition filed comments in support of the filing. NWEC contends PacifiCorp has been underfunding and underachieving energy savings and believes the time is ripe for a significant expansion of effort. The commission should make it clear, NWEC said, that utility performance not be measured on expenditure of funds, but on the actual energy savings acquired.

Rocky Mountain Power proposes these changes:

- Expanding the FinAnswer Express program, which provides incentives for commercial and industrial customers in efficient lighting, premium motors and mechanical upgrades to heating and cooling systems. Both new construction and retrofit projects are eligible. Rocky Mountain Power reports there is a waiting list of business customers wanting to participate.
- Adding the Energy FinAnswer program to its Idaho jurisdiction. Rocky Mountain Power, which operates as PacifiCorp in five other Western states, offers this program in other states. It would provide incentives and honorariums to builders of new construction projects that exceed current Idaho energy code by at least 10 percent.
- Modifying and updating the Irrigation Energy Savers program, which helps irrigators with system upgrades, including the installation of frequency drives on pumps that help them to operate more efficiently.
- Modifying the Home Energy Savings program to increase participation and align incentive levels with Idaho markets. The program provides incentives for residential customers for more efficient use of washing machines, dishwashers, water heaters, lighting, evaporative cooling, insulation and heat pumps.

Other programs funded by the rider that will continue without change are Refrigerator Recycling, Low-Income Weatherization Services and the Irrigation Load Control Credit Rider.

January 16, 2008
Case No. IPC-E-07-17, Order No. 30485
Contract with Raft River geothermal project approved

The commission approved a sales agreement between Idaho Power Co. and a Raft River geothermal facility owned by U.S. Geothermal.

Idaho Power originally had a PURPA contract with Raft River Energy I LLC, but, at the time the PURPA contract was approved, the upper limit on generation from the Raft River project was 10 megawatts. The sales agreement will allow delivery of 13 MW and is the first phase of what will eventually be a 45.5 MW plant. The project is about 15 miles southeast of Malta.

The sales agreement is beneficial to Idaho Power ratepayers, the commission said, because the rates Idaho Power must pay for the power under the sales agreement are less than they would have been under a PURPA contract.

PURPA, the Public Utility Regulatory Policies Act of 1978, requires utilities to buy energy from small renewable power projects at a rate set by state commissions. By transferring the Raft River project from a PURPA project to a more traditional power purchase agreement, Idaho Power will be able to accept more energy from the developer. Further, Idaho Power claims, the price of the energy under the 25-year agreement will be about $20 per MWh less at contract's end than under a PURPA contract. Idaho Power projects the power purchase agreement in 2032 will be about $73.92 per MWh compared to about $93.14 per MWh under a PURPA agreement.

The commission denied Idaho Power's request to have all the costs from the project passed on to customers through the company's annual Power Cost Adjustment (PCA) process. Typically, the entire cost of PURPA projects is passed on to customers while the cost of power purchases from larger generators is divided between customers and utility shareholders, with customers paying 90 percent and shareholders, 10 percent. The commission said Idaho Power could have full recovery for the first 10 MW of generation, but remaining power costs should be subject to the 90/10 split accorded all non-PURPA projects.

U.S. Geothermal, Inc., based in Boise and Vancouver, British Columbia, was selected in a bid process undertaken by Idaho Power as part of the utility's effort to include 100 megawatts of geothermal power in its power supply mix. Geothermal energy is recovered from the heat of the Earth's interior that typically appears in the form of volcanoes, hot springs and geysers.

August 8, 2008
Case No. IPC-E-08-09, Order No. 30608
PUC accepts sale agreement between Idaho Power, anaerobic digester

The commission approved an Idaho Power Co. application to buy power from an anaerobic digester to be built alongside the Big Sky Dairy near Gooding.

The proposed 20-year contract with DF-AP#1 LLC is for 1.5 megawatts of generation. DF-AP, based in Ferndale, Wa., has a scheduled operation date of Feb. 14, 2009.

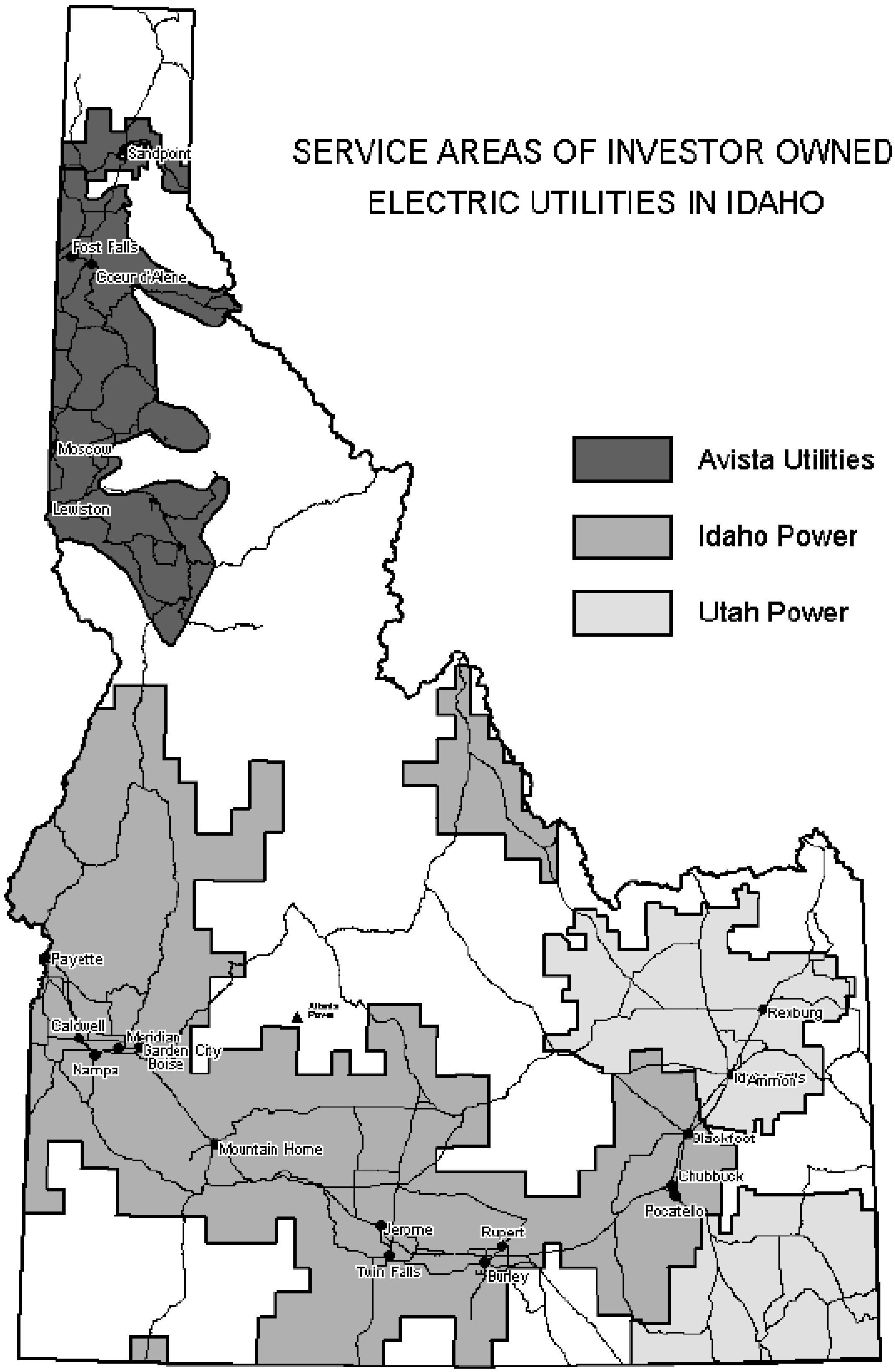
Unique to this PURPA contract is a clause that requires DF-AP to pay a stipulated amount if the project does not come online by its contracted date. Commission staff said the provision is reasonable because at least six separate PURPA facilities have failed to meet their contractual online dates with Idaho Power.

The commission agreed that a delay security provision is reasonable to protect the utility against potential default or failure. However, the commission is concerned that such provisions could have a "potentially deleterious effect" on future PURPA projects. "Quite often, operators of qualified small-power production facilities do not have ready access to the necessary amount of security or capital delineated in this agreement." The commission said delay security provisions should come close to reflecting Idaho Power's increase in power supply costs if the project fails to meet its scheduled online date and not be significantly greater than that amount so as to be "punitive in nature."

August 14, 2008
Case No. IPC-E-08-12, Order No. 30614
Air condition cycling program expands to air base

Idaho Power Co. expanded its air conditioner cycling program to Mountain Home Air Force Base. During 2007, about 13,600 customers volunteered to participate in the program which allows Idaho Power to cycle residents' air conditioners from a remote location. Customers receive a $7 per month credit for participating.

The agreement with the Air Force Base includes about 1,100 residences. Because the base is a single customer with multiple residences, the agreement provides for a cumulative credit on the Air Force base's September bill at the end of the air conditioning season. Participation in Idaho Power's overall air conditioner cycling program reduced demand by 10.8 megawatts during last July. One megawatt is enough energy to power roughly 650 homes.


SERVICE AREAS OF INVESTOR OWNED ELECTRIC UTILITIES IN IDAHO
Avista Utilities
Idaho Power
Utah Power
Sandpoint
Post Falls
Coeur d'Alene
Moscow
Lewiston
Payette
Caldwell
Meridian
Garden City
Boise
Nampa
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