

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

2006 Average Number of Customers/Avg. Revenue/kwh

(Computed from data available in FERC Form 1 Annual Reports)

374,527 Residential Customers/\$0.0594

71,472 Commercial Customers/\$0.0429

122 Industrial Customers/\$0.0295



Avista Utilities

2006 Average Number of Customers/Avg. Revenue/kwh

(Computed from data available in FERC Form 1 Annual Reports)

99,653 Residential Customers/\$0.0650

15,753 Commercial Customers/\$0.0656

494 Industrial Customers/\$0.0415



2006 Average Number of Customers/Avg. Revenue/kwh

(Computed from data available in FERC Form 1 Annual Reports)

PacifiCorp/Rocky Mountain Power

53,148 Residential Customers/\$0.0487

7,460 Commercial Customer/\$0.0632

3,441 Industrial Customer/\$0.0360

Rate adjustments

Rocky Mountain Power was granted an average 6.4 percent rate increase that became effective Jan. 1, 2008. For residential and irrigation customers, the increase was 4.89 percent. The case was settled. Rocky Mountain Power had originally requested an average 10.3 percent rate increase.

Another settlement in the **Idaho Power Co.** rate case was pending at year's end. That utility also proposed a 10.3 percent rate case, but a settlement of all parties involved proposed an average 5.2 percent rate increase. The residential increase proposed is 4.7 percent, while all other customers classes would get a 5.65 percent increase if the settlement is eventually approved.

Avista Utilities' Power Cost Adjustment (PGA) resulted in a 2.2 percent overall increase (1.5 percent for residential customers) that became effective Oct. 1, 2007. A dry winter and spring resulted in a more dramatic PCA increase for Idaho Power customers. An average 14.5 percent increase became effective on June 1.

Rocky Mountain Power granted 6.4 percent increase
Case No. PAC-E-07-05, Order No. 30482
December 28, 2007

Electric rates for customers of Rocky Mountain Power in eastern Idaho increased by an average 6.4 percent on Jan. 1, 2008. The size of the increases varied by customer class. For residential and irrigation customers, the increase was 4.89 percent.

The Idaho Public Utilities Commission approved a settlement between the utility and customer groups to increase Rocky Mountain Power's annual revenue by \$11.5 million. Rocky Mountain Power originally sought an average 10.3 percent increase and \$18.5 million in additional annual revenue.

The settlement was signed by all the parties in the case including Rocky Mountain Power, commission staff, the Idaho Irrigation Pumpers Association, the Community Action Partnership of Idaho, a consumer group that fights the causes of poverty, and two large customers of Rocky Mountain Power: Monsanto and Agrium. Timothy Shurtz, a Firth resident representing himself, also signed the settlement.

The company said the rate increase was needed to meet the demands of higher costs for fuel, labor and transmission wheeling as well as to cover additional investment in generation, transmission and distribution plants.

In actual cents per kilowatt-hour, the rate for residential customers (average summer rates and winter rates) increases from 8.36 cents to 8.76 cents. For those customers on the company's residential time-of-day program, the rate increases from 6.77 cents to 7.10 cents. For irrigation customers, the average rate increase is from 6.68 cents per kWh to 7 cents.

The company was authorized to earn a rate of return up to 8.27 percent. The commission approved a return on equity of 10.25 percent. The company requested 10.75 percent. Rocky Mountain Power is currently earning on ROE of 5.3 percent and said a higher ROE is warranted to attract the capital necessary to maintain its utility infrastructure.

Highlights of the settlement included:

- An agreement with irrigators that those who participate in the company's Dispatchable Irrigation Load Control Program will get nearly twice as large a credit – from \$11.19 to \$23 – for every kilowatt of peak demand reduced. That can be increased to \$26 per kilowatt if total participation reduces more than 150 megawatts of peak demand and \$28 if total participation reduces more than 175 MW of peak demand. The program allows the company to remotely interrupt irrigation service during peak times.
- Agreements with Monsanto Corporation, the utility's largest customer and Agrium, both based in Soda Springs, that spread rate increases over three years and increase the amount of an interruption credit granted Monsanto. Rocky Mountain originally proposed a 24.1 percent increase for Monsanto and 14.5 percent increase for Agrium. The settlement allows a 13.5 percent increase for Monsanto on Jan. 1, 2008, another 3 percent on Jan. 1, 2009 and 5 percent on Jan. 1, 2010. Agrium will get a 6.25 percent increase on Jan. 1, 2008, another 3 percent on Jan. 1, 2009 and another 7 percent on Jan. 1, 2010. Rocky Mountain further agrees to not increase rates for Monsanto and Agrium beyond what is proposed even if the cost to serve those classes increases before Dec. 31, 2010. If there are increases in cost of service to Monsanto and Agrium, Rocky Mountain Power agrees to assume those losses and not propose they be assigned to other customer classes.
- An increase in the credit paid Monsanto for agreeing to have its electrical load reduced by the company during peak operating times. Monsanto, an elemental phosphorous plant, consumes about 1.4 million megawatt-hours of electricity, roughly 42 percent of Rocky Mountain's Idaho electrical load. Monsanto can provide up to 162 MW of electricity for the company by having service to its three furnaces curtailed. Interruptions can occur within seconds to meet system emergencies to provide operating reserves for the utility. For non-emergency curtailments, such as economic curtailments, two hours notice to Monsanto is required.
- The commission acknowledged that the percentage increases for street-lighting customers, primarily cities, of about 75 percent is high, but the actual dollar amount is not excessive and is needed to meet the cost of service to that customer class. Some city officials testified at hearings and workshops in eastern Idaho, expressing concern about the street lighting increase. The commission noted the actual dollar increase is not excessive, especially when considering that the costs to serve the street lighting classes have increased by 80.7 percent since the last rate case. "Cost of service results have historically fluctuated for the street lighting classes, more so than larger customer classes," the commission said, but noted this is the first proposed revenue increase for street lighting classes in many years. "We find that moving the street lighting classes to full cost of service is justified on equity principles. Should the increase not be borne by these particular classes, the revenue shortfall would be shifted to those classes already receiving a rate increase," the commission said. "For street lighting customers, it is a large percentage increase, but the related dollar amount, we find, is not likely to impose undue economic hardship."

A dry winter and spring resulted in customers of Idaho Power Co. paying more for power supply. The Idaho Public Utilities Commission approved Idaho Power Co.'s application to implement a 0.24-cent per kWh surcharge to pay for extraordinary power supply costs not already covered in base rates.

The increase varied in size according to customer class. Residential customers received an 11 percent increase; small commercial, 8.8 percent; large commercial, 16.6 percent; irrigation, 14.6 percent and industrial, 22.5 percent. The average increase for all customer classes was 14.5 percent.

What is the power cost surcharge (PCA)?

Customer rates are divided into two components, the base rate and the power cost adjustment or PCA. (In the case of gas utilities, this same mechanism is called the "purchased gas cost adjustment" or PGA.) The normal costs for supplying power are recovered in the 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. The PCA annually increases (through a one-year surcharge) or decreases (with a credit) customer rates to account for above-normal or below-normal power supply costs. Yearly PCA adjustments, up or down, do not affect the utility's earnings. The money collected from the PCA is essentially a pass-through, passing directly from the utility to its power suppliers.

Simpler definition: The base rate includes the cost of everyday operations. The power cost adjustment includes the variable costs of energy.

Due to low water, the company's hydroelectric dams cannot generate enough electricity to meet customer demand, so the company must acquire power from other sources. **The revenues from the one-year surcharge go directly to pay for power supply and do not enhance company earnings.**

In 2006, customers received an average **19.34 percent reduction in rates** due to favorable water conditions. Due to dry conditions in 2006-07, the company calculated its annual power costs were \$77.5 million more than what was collected in 2005-06 PCA rates.

For an average customer who uses 1,050 kWh per month, the monthly increase was \$6.41, according to the company's figures. Customers were getting a **credit** of 0.37 cents per kWh. Thus, the increase from a negative 0.37 cents to a positive 0.24 results in customers paying a **surcharge**, an additional 0.61 cents per kWh. Adding in the proposed PCA, the non-summer residential rate increased from 5.05 cents per kWh to 5.66 cents.

The forecasted runoff from the mountains upstream of Brownlee Reservoir was 3.3 million acre-feet. During 2005-06, the runoff was 8.4 maf. During an average year, the runoff is 6.3 maf.

The Industrial Customers of Idaho Power (ICIP) filed comments, agreeing with the company's calculations and stating the PCA be approved. However, ICIP wanted the PCA to be subject to refund while the commission initiates a proceeding to modify the mechanism that calculates the PCA. ICIP proposed a "balancing account" be left in the PCA that would reduce the volatility of the increases and decreases to the PCA. Last year, industrial customers got a 27 percent reduction, while this year they are getting a 22.5 percent increase.

Commissioners opposed the ICIP proposal. "The existing PCA methodology contains a true-up mechanism so that customers will pay no more or no less than the PCA requires," the commission said.

The true-up mechanism aligns Idaho Power’s year-ahead forecast of power supply costs with the actual costs incurred during the year. If actual costs are higher than forecast, customers get a surcharge. If actual power supply costs are less than forecast, customers get a credit. “We further find that the current PCA methodology with its true-up mechanism provides customers with timely ‘price signals’ so that customers have the opportunity to adjust their usage given higher PCA rates,” the commission said.

Avista allowed recovery of extraordinary expenses

Case No. AVU-E-07-07, Order No. 30429

September 14, 2007

The portion of Avista Utilities’ customer bills that goes to pay for extraordinary power supply costs increased by about 1.5 percent for residential customers – and 2.2 percent overall – beginning Oct. 1. For an average residential customer who uses 1,000 kWh per month, the increase is about \$1.04 per month.

The surcharge was 2.45 percent, or about 0.163 cents per kWh, and increased to about 0.267 cents per kWh. The surcharge has been as high as 19.4 percent when the Western energy crisis of 2000-01 caused unprecedented increases in wholesale power prices. It has been dropping steadily until 2007.

The surcharge does NOT affect company earnings and does not go to pay salaries or finance any company operations. The surcharge is essentially a “pass-through,” collected from ratepayers, kept in a deferred account, and then passed directly to wholesale power and fuel suppliers. The commission’s job is to review the surcharge request to make sure the power supply and fuel expenses incurred by Avista were necessary to serve customers and were the most reasonably priced available to the company at the time. State statutes require that regulated utilities recover all prudently incurred expenses and earn a reasonable rate of return.

Commission OKs permanent PCA mechanism for Avista

Case No. AVU-E-07-01, Order No. 30361

July 6, 2007

The Idaho Public Utilities Commission approved a yearly adjustment to rates for Avista Corporation that will allow the utility to recover extraordinary power supply expenses not already included in base rates. The yearly Power Cost Adjustment (PCA) mechanism is similar to one that has been in place for Idaho Power Co. customers since 1993.

The yearly adjustment will increase or decrease rates depending on conditions outside the company’s control that can dramatically alter power supply expense. Those conditions include variations in hydroelectric generation cause by lack of streamflows or unanticipated changes in fuel costs or wholesale market prices for energy.

The updated PCA will be effective Oct. 1 of each year. Each year when Avista files its PCA, the commission will review the application to make sure the power supply and fuel expenses incurred by Avista were necessary to serve customers and were the most reasonably priced available to the company at the time.

Idaho Power rate case pending at year's end

Case No. IPC-E-07-08

At year's end, parties to an Idaho Power Company rate case were asking state regulators to approve a settlement that increases rates for residential customers by about 4.7 percent and by about 5.65 percent for all other customers. The annual revenue increase to the company, under the settlement, would be 5.2 percent.

When Idaho Power filed the case in June, it asked for an increase in annual revenue of \$63.9 million, or 10.35 percent. The proposed settlement would allow the company an annual revenue increase of \$32.1 million or 5.2 percent.

Idaho Power, commission staff and intervenors began participating in settlement discussions in late October. Intervenors in the case include the Idaho Irrigation Pumpers Association, the Industrial Customers of Idaho Power, Micron Technology, Inc, the U.S. Department of Energy and Kroger Company. All the parties, with the exception of Kroger, signed the settlement. Kroger, which represents the Fred Meyer and Smith's Food King stores in Idaho, agreed with the majority of the settlement, but wanted large commercial customers like itself to be afforded a Time of Use rate similar to that allowed industrial customers.

The proposed increase for residential customers of 4.7 percent is very close to the company's original 4.5 percent proposal. The company originally proposed a 15 percent increase for small commercial, 13.1 percent for large commercial, 15 percent for industrial and 20 percent for irrigation customers. Instead, the settlement proposes a 5.65 percent increase for all those customer classes. The parties requested a March 1, 2008, effective date for new rates.

The settlement proposed that issues not resolved in the case be addressed in 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.
- 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.

Ninth Circuit Court decision suspends BPA credit

The biggest impact to electric rates during 2007, particularly to Rocky Mountain Power customers in eastern Idaho was not even tied to a rate case.

A panel of three judges on the Ninth Circuit Court of Appeals in May declared that the Bonneville Power Administration did not act in accordance with the law when it negotiated a settlement regarding the distribution of wholesale power and credits to electric utilities and customers in the Northwest. Because of the court's decision, BPA suspended the Residential Exchange Program (REP) credit to customers of investor-owned utilities in four Northwest states.

What is the Bonneville Power Administration?

The BPA is a federally owned wholesale power marketer, selling electricity at cost to customers in Oregon, Washington, Idaho and Montana. The electricity is generated from a number of hydroelectric facilities along the Columbia River and its tributaries.

For Rocky Mountain Power, suspending the credit resulted in an average 28 percent rate increase for residential customers and a 51 percent increase for irrigation customers. To soften the blow for irrigation customers, the company proposed and the commission agreed to immediately end the residential credit and to use the remaining amount in the REP fund balance to carry irrigators through until the balance zeroed out in about mid-July. The company maintained that residential customers had already received the benefit during 2007 during the winter heating season, but irrigators had not received any benefit by May's end since the season was just beginning.

For Idaho Power, the result was a 9.3 percent increase for average residential customers or about \$5.35 per month. For Avista customers, the residential increase was an average 9.5 percent.

The Idaho commission joined commissions in Oregon, Washington and Montana asking the Ninth Circuit for a re-hearing on the issue. Re-hearings are granted in cases of "exceptional importance." The commissioners said this case easily meets that standard. "Indeed, it is difficult to imagine decisions that would have more direct impact on such a large number of people," the commissioners said.

The Northwest Power Act of 1980 requires that residential and small-farm customers in the Northwest share in the benefits of the region's federal hydroelectric projects. Customers of public utility districts, such as rural co-ops and municipalities, typically benefit from the federal hydroelectric system with preferential access to low-cost federal power provided by BPA. Customers of the region's investor-owned utilities, such as Idaho Power, receive their share of the benefit through a Residential Exchange Program (REP) that results in financial credits on the electric bills of residential and small-farm customers.

The amount of the credit is determined by formulas using various factors, including a utility's average system cost for producing power. In 2000, BPA offered the region's investor-owned utilities the option of entering into a settlement in lieu of a more traditional REP calculation. Several public utility districts challenged the settlement, alleging BPA had overstepped its authority under the Northwest Power Act and that the result was too small a benefit to publicly owned utilities and too large a benefit to customers of investor-owned utilities. The court ruled in favor of the public utility districts, eliminating the REP for the first time in nearly 30 years until a new settlement can be reached.

Wind issues continue to dominate

As was the case during 2005 and 2006, the increasing development of wind as an energy source posed new questions for the commission, regulated utilities and wind developers.

IPC-E-07-03, AVU-E-07-02, PAC-E-07-07

A case that began in 2005 to determine the cost to utilities to integrate wind transmission into their respective electric grids was nearing resolution at the end of 2007. Idaho Power, later joined by PacifiCorp and Avista, received and sought commission approval to suspend the company's federal obligation to buy wind power from independent developers of small wind projects to allow time to further examine a fair price for wind given its unpredictable output. The commission temporarily lowered the size of non-firm wind projects that can qualify for a published government rate from 10 megawatts to 100 kilowatts. (*See definition of PURPA rate at right.*)

What is PURPA?

Congress passed the Public Utility Regulatory Policies Act during the energy crisis of the late 1970s. One of its stated goals is to encourage development of renewable energy technologies as alternatives to burning fossil fuels or constructing new power plants. The federal act requires that electric utilities offer to buy power produced by small power producers or co-generators who obtain Qualifying Facility (QF) status. The published rate to be paid project developers is set by state commissions and 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.

Since then, Idaho Power Co., as well as the two other major electric utilities that serve the state, Avista Corporation and PacifiCorp, completed studies to determine wind integration costs and later proposed that the published rate for wind be discounted and that the size limit of projects that can qualify for the rate be brought back up to 10 MW.

The three utilities differ on exactly how much the discount for wind integration should be, but the proposals are in the \$5 to \$10 per megawatt-hour range. The current posted rate for generation from renewable small-power projects, absent a discount rate, is about \$64 per MWh.

The utilities also propose that wind developers reimburse them for the cost of state-of-the-art wind forecasting services and, further, that developers provide guarantees that their wind projects are mechanically able to generate at full output during 85 percent of the hours during a month. If the wind developers agree to these provisions, the utilities would agree to support removal of the "90/110 performance band" now required in wind contracts. That requirement stipulated that when output was less than 90 percent of projections or more than 110 percent of projections, that Idaho Power could pay developers a market-based rate rather than the posted rate.

Commission staff conducted two workshops to explore whether the utilities and wind developers could agree to a generic wind integration adjustment, but the parties were unable to settle. With the parties unable to agree, the matter was before the commission for a decision at year's end.

The commission approved a negotiated settlement between wind developers and Idaho Power Co. on who should pay for transmission upgrades required to accommodate about 200 megawatts of new wind generation planned in the Twin Falls area.

A complaint filed by Cassia Gulch Wind Park and Cassia Wind Farm alleged that an Idaho Power plan to require small-power producers to pay for nearly \$60 million in transmission upgrades to accommodate new generation threatened the economic viability of a number of wind projects and would stifle further development of renewable energy in Idaho. The developer, Jared Grover, asked the commission to determine that costs to upgrade the 138-kV transmission system in the Magic Valley be borne by all Idaho Power ratepayers, not just small-power producers.

The settlement significantly reduced the amount needed to invest in transmission upgrade from \$60 million to \$11 million. Cassia agreed to install, at its expense, equipment and communication facilities that will allow it to reduce its energy output to a predetermined point within 10 minutes of when Idaho Power asks for a reduction. Under the proposed settlement, Idaho Power would issue a "redispatch" notice to Cassia and other wind developers when it needs to act quickly to reduce transmission over-loads.

Idaho Power has the transmission capability to handle the anticipated 200 MW in new generation under normal circumstances. However, existing transmission capacity is not sufficient to meet the company's required reliability standards during times of emergency, such as when transmission lines are out of service. The willingness of Cassia and future wind generators in the area to be able to reduce output when Idaho Power issues a redispatch notice will obviate the need to install major transmission upgrades.

The parties also proposed, and the commission accepted, a formula to pay for the \$11 million in transmission upgrades required to accommodate generation from Cassia and other anticipated wind projects in the Magic Valley. Idaho Power will pay 100 percent of the costs for the first phase of the five-phased upgrade. For the remaining four phases, 25 percent of costs will be provided by the developer and 25 percent by Idaho Power Co. The 25 percent provided by the company will be included in rate base for future recovery from customers systemwide. The remaining 50 percent would be advanced by the developer, but refunded over a term not to exceed 10 years after the projects are commercially viable. The refunded amounts would then be included in rate base.

The transmission upgrades, Idaho Power said, will provide the company with a more robust transmission system serving the Magic Valley and the Wood River Valley. Further, the generation Idaho Power anticipates from other wind projects in the area, about 60 to 80 MWs, would satisfy a major portion of future generation identified as necessary in the company's Integrated Resource Plan.

The commission granted a request by utilities to adjust rates paid small-power producers so they more closely match the actual value of energy at the point of time it is delivered.

The value of energy increases during peak demand times and decreases during light-load hours, yet utilities maintain they must pay the same price to the small-power generator during light load hours as it pays when the energy is delivered during heavy load hours.

In a related matter, the commission denied a request by utilities to place further restrictions on the distance allowed between wind projects, or other small-power generation projects, which are owned by the same entity.

Under the federal Public Utility Regulatory Policies Act of 1978 (PURPA), regulated utilities must buy power from generators of renewable energy at a rate that is published by state utility commissions. That rate, about \$62.40 per megawatt-hour at the case's filing, is called the avoided-cost rate and is typically more attractive than market rates. The rate is to be based on the cost the utility avoids when it buys from a PURPA project and thus does not have to generate the power itself or buy it from another source.

Utilities are already allowed a reasonable adjustment to account for the changing value of energy between the various seasons of the year. But because the value of energy fluctuates hourly, Idaho Power Company and Rocky Mountain Power petitioned the commission for a daily load shape adjustment, similar to one granted Avista Utilities in northern Idaho. The revision does not change the computation of the avoided-cost rate but could change the revenues received by small-power producers depending on the times during the day they deliver their energy.

Idaho Power proposed a daily load shape adjustment of \$11.63, as the weighted difference between light-load hours and heavy-load hours. However, commission staff proposed and the commission adopted an adjustment of \$7.28. For Rocky Mountain Power, the difference, on average, is \$7.18.

Idaho Power and Avista also asked the commission to adopt a rule, similar to one approved in Oregon, which prevents utilities from having to pay the published avoided-cost rate when the same owner/developer has small-power projects located within five miles of each other. Current federal regulations state that projects must be at least one mile apart.

The utilities allege some wind developers build their projects at or near the size limit to qualify for the published PURPA rate and then locate another similar-sized project close by and still qualify for the published rate simply by creating a separate legal entity, although ownership does not change.

But the commission said the public interest would not be served by the more restrictive rule. "It is a change that we find would encourage and might actually promote gamesmanship," the commission said.

PUC modifies method to calculate rates paid small-power developers
Case No. IPC-E-06-29, Order No. 30220
December 28, 2007

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.

In September, Idaho Power 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 Idaho PUC averages the first three years of that forecast and also includes 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 was 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, Idaho Power said, because costs for PURPA contracts are passed on to customers.

Instead, 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.

The commission agreed with Idaho Power that workshops should be scheduled to determine whether other variables used to calculate avoided-cost other than just the fuel component need to be updated as well.

Idaho Power signs 20-year agreement with 100-MW wind project

IPC-E-06-31, Order No. 30259

February 27, 2007

The commission approved a major wind agreement between Idaho Power Company and Houston-based Telocaset Wind Power Producers LLC. The agreement for 100 megawatts of wind energy generated from a wind farm in eastern Oregon is needed to meet Idaho Power's growing demand, the commission said.

"Moreover, the addition of wind generation to the western side of the company's service territory adds some geographic diversity to its growing portfolio of wind resources," the commission said. Most of Idaho Power's wind projects are on the company's eastern side, in south-central Idaho. Telocaset's wind farm is in eastern Oregon's Union County near North Powder. Energy will be delivered to a point on the La Grande-Brownlee 230 kV transmission line.

The 20-year sales agreement with Telocaset, sometimes referred to as the Horizon project, starts at a base rate of \$48 per megawatt-hour with an annual escalation rate of 3 percent. The levelized cost of the contract over the entire 20 years is estimated at \$62.38 per MWh.

The agreement has provisions similar to those included in the company's agreements with small wind projects that penalize Telocaset if output does not meet projections. The agreement provides that Telocaset will deliver detailed forecasting data, including forecasts of energy to be delivered during the next hour, day and week. The data will assist Idaho Power to integrate the wind power into the utility's resource supply mix. The project, scheduled to be operating by March 21, 2008, is expected to generate its most output during those times of winter and summer when there is peak demand on Idaho Power's overall generating system.

The estimated cost of transmission upgrades and interconnection to Idaho Power's transmission system is \$3.6 million. Of that, an estimated \$2.3 million is the expense required to allow Telocaset to interconnect with Idaho Power's transmission system. Telocaset will pay all the costs related to interconnection. The remaining \$1.3 million is the estimated expense for upgrades to the company's general transmission system. Because those upgrades benefit all customers, Telocaset will be eligible to have that amount refunded by Idaho Power after it makes the initial investment for those upgrades.

Idaho Power's 2004 growth plan, called an Integrated Resource Plan, said the company would solicit bids for 200 MW of wind energy. In September 2005, the request-for-proposals was revised downward to ask for 100 MW because of the quantity of wind the company was getting from small-wind projects in the state. Telocaset was selected as the preferred bidder from among seven bids representing 19 projects between 45 MW and 200 MW. In its findings, the commission said the RFP process was "conducted in a fair and reasonable manner" that resulted in the selection of the best proposal.

Three organizations, the Northwest Energy Coalition, the Renewable Northwest Project and the Idaho Farm Energy Association submitted comments for the case record.

The Northwest Energy Coalition and the Renewable Northwest Project said the agreement would be beneficial to both Idaho Power and ratepayers and furthers renewable energy in Idaho Power's mix of

energy resources. The rate is one of the most cost-effective of all generation sources identified in Idaho Power's long-range plan, the groups said.

The Idaho Farm Energy Association said the contract is a wise investment for ratepayers, but noted that the project is a \$160 million investment in a rural Oregon county while Idaho customers pay for the energy. The organization said projects similar to this, which typically generate more than \$1 million per year in local economic benefits, are desperately needed in rural Idaho.

Commission approves delay for two wind projects

IPC-E-06-34 and -35, Order Nos. 30398, 30399

August 15, 2007

A wind developer was given another year to get two projects online before having to pay Idaho Power Company damages.

The commission approved changes in two contracts with Hot Springs Wind Farm LLC and Bennett Creek Wind Farm LLC that originally required the projects to be online by Dec. 31, 2007. The developer of the projects, Energy Vision LLC, said unanticipated upgrades to Idaho Power's transmission network are needed before the Elmore County projects can be built. More time is needed to conduct the necessary studies and build the interconnection facilities to accommodate the projects, Energy Vision claimed.

The delay in interconnection caused the projects' investor and wind turbine supplier to reallocate the turbines to other projects, forcing Bennett Creek and Hot Springs to wait for the next available turbines. One of the contract amendments requires a modification of the type and size of wind turbines.

Both Bennett Creek and Hot Springs have agreed to provide Idaho Power with liquid security in an amount sufficient to cover the delay liquidated damages in the event the projects do not meet new deadlines. Idaho Power said it is aware of other wind projects facing similar delays and proposed that the agreement with these wind farms be a template for similar resolution to other projects. However, the commission declined that request, although it did accept the liquid security provisions for these two projects.

Both projects will include 12 wind turbines that will deliver an average 10 megawatts per month. The developer of both projects is Glenn Ikemoto of Energy Vision LLC, based in Piedmont, Calif.

Idaho Power-Alkali wind agreement approved

IPC-E-06-36, Order No. 30253

February 27, 2007

Idaho Winds LLC plans to build a wind generation project six miles northwest of Glens Ferry. Its sales agreement with Idaho Power Co. was approved by the commission.

The Alkali Wind Farm includes 12 turbines that will be operating by Dec. 31. Even though the maximum output of the project is 18 megawatts, Idaho Winds will not generate more than 10 average megawatts on

a monthly basis. Energy delivered in excess of that amount may be accepted but Idaho Power will not be obligated to pay for it. The president of Idaho Winds LLC is Rick Koebbe of Boise.

The project is a Qualified Facility under the provisions of the federal Public Utility Regulatory Policies Act.

The agreement does include provisions that require the project to pay Idaho Power damages if the project comes on-line after Dec. 31. The delay damages will accrue for up to 90 days.

The project is also one of the first to come under changes in company's interconnection tariff, including a requirement that small-power producers enter into an interconnection agreement as well as a sales agreement with the utility.

Idaho Winds has not yet signed an interconnection agreement with Idaho Power, but anticipates doing so by year's end. A feasibility study indicates that upgrades to both Idaho Power's local distribution system and transmission system are necessary. Costs associated with those upgrades could be reduced if other projects in the area will use some of the same transmission facilities, although cost-sharing arrangements have yet to be worked out.

IRPs: Planning for the future

The commission requires regulated utilities to file an Integrated Resource Plan (IRP) every two years. The 10-year growth plan projects future load requirements and how utilities plan to deliver low-cost, reliable energy to its customers. The document is only a guide and not a commitment to resource acquisition.

Idaho Power Company
Case No. IPC-E-06-24, Order No. 30281

Idaho Power Company's 20-year growth plan calls for 1,300 MW of added generation from wind, geothermal, coal and nuclear resources to meet the demands of its growing customer base.

The plan also calls for 187 megawatts of demand reduction through conservation and energy efficiency measures referred to in the industry as demand-side management (DSM) programs. Idaho Power also plans to gain access to an additional 285 megawatts as a result of transmission expansion and upgrades that will bring in more power from the Pacific Northwest.

The commission said Idaho Power's 2006 IRP is an improvement from prior filings, particularly in its inclusion of transmission upgrade and expansion as a method to acquire new sources of energy supply. "We are also pleased that the company is expanding its DSM programs and increasing the amount of renewable energy resources in its portfolio," the commission said.

The commission asked that Idaho Power and the two other major regulated utilities that serve the state – Avista and PacifiCorp – consider jointly filing their IRPs in order to provide the commission with a more regional view for resource planning.

Idaho Power projects its customer base will increase from 455,000 to more than 680,000 over the next 20 years.

The company recently entered into an agreement with the developers of an eastern Oregon wind farm for 100 megawatts to add to its growing wind portfolio. The company has increased its wind portfolio from 2.61 megawatts in 2004 to nearly 400 MW scheduled to be online by the end of 2008.

The plan includes a 250-megawatt coal addition in 2013. Idaho Power said it does not know specifically where this addition will be located, but states that one of its best near-term alternatives is an expansion at the Jim Bridger coal plant near Rock Springs, Wyoming. The plan also anticipates a possible 250 megawatts from a regional facility that would use an advanced clean-coal technology called Integrated Gasification Combined Cycle. IGCC developers have expressed interest in Pocatello and Soda Springs as possible sites for the advanced coal technology. Preliminary results indicate IGCC technology may be viable, but the high initial capital expenditure and unproven technology may be barriers.

Idaho Power recently named U.S. Geothermal Inc. as the successful bidder for an approximate 45.5 MW

of geothermal resources from a plant in eastern Oregon and one under construction near Raft River, Idaho. Idaho Power is seeking to add a total of 100 MW of geothermal resources over the next 20 years.

The company also plans to acquire 150 megawatts through the use of combined heat and power, or industrial cogeneration. Many manufacturers, such as lumber plants, produce steam as a byproduct of their manufacturing process and can sell that steam generation to electric utilities.

In 2023, Idaho Power may be able to acquire 250 MW from an anticipated nuclear facility at the Idaho National Laboratory in eastern Idaho.

Several organizations submitted comments for the commission to consider regarding Idaho Power's IRP.

Citizens Protecting Resources, an organization formed in response to the proposed siting of a large coal plant near Jerome, said the IRP did not include a strong DSM plan and didn't place enough emphasis on non-hydro renewable resources.

The **Northwest Energy Coalition** commended the company's increase use of DSM programs, but expressed concern about the amount of thermal resources that are proposed, such as coal. The coalition said the company should consider more transmission improvements in southern Idaho to accommodate additional wind energy.

The **Industrial Customers of Idaho Power** urged the commission to reject the plan because of its inclusion of the Evander Andrews natural gas-fired plant near Mountain Home. ICIP said the company should use emergency back-up generators during times of peak demand rather than building additional plants. It also said the company focuses on transmission upgrades in the northwest but does not consider more transmission access to markets east of its service territory.

The **Idaho Irrigation Pumpers Association** commended the company for a realistic plan and one that included a diverse resource base. It urged the company to continue with its DSM programs for irrigators and other customer classes.

Exergy Development Group of Idaho LLC, which develops wind generation, criticized the plan for focusing too strongly on transmission upgrades to the Pacific Northwest, ignoring development to the east and south. Idaho Power said transmission upgrades to the east have been proposed, but are not finalized.

Rocky Mountain Power

Case No. PAC-E-07-11

October 22, 2007

PacifiCorp, a six-state electric utility that operates as Rocky Mountain Power in eastern Idaho, plans to serve its growing customer load in future years by adding about 2,000 megawatts of renewable power, most from wind, over the next 10 years. PacifiCorp also plans additions to gas and coal facilities, though none of those expansions are planned in Idaho.

PacifiCorp, with about 68,000 customers in eastern Idaho, expects to grow at an annual rate of 2.5 percent in its six states. Growth on the east side of the company's territory, which includes Wyoming, Utah and Idaho, is expected to be 3.2 percent. PacifiCorp anticipates 0.8 percent growth on its western side, which includes Washington, Oregon and northern California. The company anticipates a 1.3 percent growth rate in Idaho alone.

Of the 2,000 MW in renewable resources, the company plans 1,600 MW of that to come from wind farms planned in Wyoming, Washington and Oregon.

Other sources include: 340 MW from a Utah coal plant in 2012 and 527 MW from a Wyoming coal source in 2014; 548 MW from a natural gas combined cycle combustion turbine (CCCT) added in 2012 and another 357 MW from a gas CCCT added in 2016, both to be built on the eastern side of the company's territory. Another 602 MW would come from a CCCT natural gas combustion turbine built on the company's west side in 2011.

Another 100 MW will come from programs that reduce demand on the system, such as irrigation and air conditioner load control programs. The company currently gains 150 MW in demand reduction from irrigation and air conditioning load control programs in Utah and Idaho.

Commission staff noted that PacifiCorp is slightly behind on its renewables acquisition target, with 335 MW of the target 400 MW expected to be online by the end of this year. While the wind projects conform to PacifiCorp's commitments, the cost has been higher than anticipated, staff noted. "This is evident with the three large wind projects expected to be online this year, each of which have capital costs far in excess of those used as assumptions in the IRP," commission staff said. However, commission staff continues to support cost-effective wind generation to serve Idaho customers, noting that these projects do not come with the price volatility that impacts fuel costs or the cost of mitigation requirements that come with carbon emissions.

Some states in PacifiCorp's territory now require the utility to procure a certain amount of its energy from renewable resources. These "renewable portfolio standards" could impact the company's Idaho customers, even though Idaho does not mandate a renewable portfolio standard on its utilities. Commission staff said the renewable standard will further constrain PacifiCorp's resource acquisition and may expose its Idaho customers to the financial impacts of resource decisions "based less on economics and more on politics." Staff urged the Idaho commission to become more involved in PacifiCorp planning processes to ensure that Idaho ratepayers are well represented.

Monsanto, an elemental phosphorus plant based in Soda Springs and PacifiCorp's largest customer in its six-state territory, expressed concern that other states in PacifiCorp's territory, namely Oregon and Utah, have disproportionate influence on PacifiCorp's capital procurements. Monsanto further stated the utility should be required to increase its demand-side reduction programs, should avoid the development of new gas-fired generation and look instead to nuclear generation and coal-fired generation using "clean-coal" technology.

Without added generation, PacifiCorp anticipates a resource deficit during times of peak use as soon as next year allowing for a 15 percent planning reserve of generation available in case of emergencies. With

no added generation, the company anticipates it will be 791 MW short, based on a 12 percent planning reserve.

Based on the company's load growth plan, total generation from pulverized coal will decrease from 64.8 percent of the company's power supply to 43.4 percent, while purchases of power from the market will increase from 4.5 percent today to 17.1 percent in 2016. Generation from the company's own renewable energy sources is slated to increase from 3.6 of total generation this year to 8.5 percent in 2016. Power from combined cycle gas plants would increase from 8.5 percent of the company's generation today to 17.4 percent in 2016. Generation from hydroelectric resources would decrease from 9.6 percent in 2007 to 6.9 percent in 2016.

The company says it will assume a leadership role in global climate change issues and continue to investigate the development of carbon reduction technology, specifically clean-coal technology, sequestration and nuclear power.

Avista Utilities

AVU-E-07-08, Order No. 30464

November 27, 2007

Avista Utilities, which serves about 115,000 customers in north Idaho, will be looking to natural gas and renewable sources of energy for added generation over the next decade. Avista plans on contracting with a natural gas plant near Rathdrum for 350 megawatts. It also plans on adding 300 megawatts from wind sources, 35 MW from other renewable resources and 87 MW from energy savings due to conservation.

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

Avista decided to drop plans for future coal-fired generation for several reasons including legislation barring its use in the state of Washington where the utility has most of its customers. The company also anticipates federal legislation in the near future that will place further limits on carbon emissions. In response to the anticipated problems with coal-fired generation, the company substituted fixed-price natural gas resources for coal-based resources. According to Avista, it has the eighth-smallest carbon footprint among major U.S. utilities.

The company had hoped for additional wind and other renewable sources beyond the 335 MW already planned. But wind development, the company said, has been hampered by a dramatic increase in the cost of wind resources since 2005. Recent legislation in Oregon, Washington and other states that mandates a certain percentage of generation from renewable sources has increased the demand for wind turbines, reducing their availability and increasing their price.

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

Conservation, energy efficiency

New rate mechanism to encourage energy efficiency is among first in nation for electric utilities

Case Nos. IPC-E-04-15, Order No. 30267

March 14, 2007

The Idaho Public Utilities Commission has approved a yearly rate adjustment designed to remove financial disincentives for Idaho Power Company to implement energy efficiency programs.

The rate adjustment, called a Fixed Cost Adjustment (FCA), is approved only on a pilot basis, subject to modification or removal by the commission.

Currently, when Idaho Power initiates programs designed to encourage customers to reduce their energy use, it negatively impacts energy sales. If customers significantly reduce their consumption through conservation efforts, the company may not recover its fixed costs of serving customers.

The FCA will be a yearly adjustment to electric rates that would prevent the company from losing money when it invests in energy efficiency programs. Often referred to in the industry as “decoupling,” the FCA removes the link between energy efficiency and energy sales by allowing the company to recover its fixed costs regardless of the volume of energy sales.

Initially, the three-year pilot program applies only to residential and small-business customers.

When the commission sets rates, it determines the annual revenue needed by the company to recover its costs. During the rate-setting process, the commission determines the fixed cost that should be recovered from residential and commercial customers. The FCA mechanism will allow for a “true-up” between fixed costs actually recovered through rates and the fixed cost amount authorized by the commission for recovery in the company’s most recent rate case. If the fixed cost recovered were less than the authorized fixed-cost rate, customers would get a surcharge that can be no higher than 3 percent. If the company collects more in fixed costs than authorized by the commission, customers would get a credit. The surcharge or credit would last one year when the FCA would again be updated. According to Idaho Power’s estimates, the impact on rates for average residential customers would typically be \$1 or less a month. The fixed-cost adjustment would be made at the same time the company adjusts bills for its annual power cost adjustment (PCA), which allows the company an opportunity to recover above-normal costs of supplying power.

In exchange for removal of the financial disincentive, the FCA requires Idaho Power to significantly increase the size and availability of energy efficiency programs and to support more energy efficient building and energy codes.

The pilot program is the result of a negotiated settlement between Idaho Power, commission staff and the Northwest Energy Coalition. In its comments, the Northwest Energy Coalition said “decoupling results in

a better alignment of shareholder, management and customer interests to provide for more economically and environmentally efficient resource decisions.”

The Idaho Citizens Action Network opposed the FCA mechanism as one that would allow Idaho Power to receive additional revenue without any proof of need. ICAN sought a more thorough review of the program and public hearings.

In its findings, the commission said the program will require close monitoring, which is why the FCA is a pilot program. Many of the issues raised by ICAN will be considered in the commission’s assessment of the program during the pilot period, the commission said.

“Promotion of cost-effective energy efficiency ... is an integral part of least-cost electric service,” the commission said. In addition to their environmental benefits, energy efficiency programs benefit all customers because they reduce or eliminate the need for the power company to meet load growth by adding new generation plants or buying additional power from the wholesale market.

IPC-E-06-32, Order No. 30268

On the same day the commission approved the FCA mechanism, it also approved a pilot program that should encourage the construction of energy-efficient homes.

Idaho Power currently provides an incentive payment of \$750 to builders for each home built to meet energy efficiency standards set forth by the ENERGY STAR® Homes Northwest program. The pilot program provides incentive payments or penalties to Idaho Power for meeting or not meeting specified participation goals in the program. The company will provide marketing to encourage more participation in the program. On average, homes constructed to the ENERGY STAR® standard in Idaho will save an estimated 2,078 kilowatt hours annually, or 30 percent greater energy efficiency than existing Idaho residential building codes.

Under this program, Idaho Power would receive an incentive payment if the market share of homes constructed under the ENERGY STAR® program exceeds 7 percent of the total number of residential building permits issued in Idaho Power’s service territory in 2007, 9.8 percent of total service area homes in 2008 and 11.7 percent of total service area homes in 2009. The amount of the incentive would equal the percentage that exceeds the target. For example, if Idaho Power were able to achieve 105 percent of the 7 percent target for 2007, it would receive a payment equal to 5 percent of the total program net benefits. The incentive would be capped at 10 percent of program net benefits. Penalties would be levied for any year Idaho Power fails to reach the market share of 4.9 percent program participation it achieved in 2006. Impact on customers’ rates would be negligible.

The Industrial Customers of Idaho Power opposed the program, saying customers should not be required to pay Idaho Power to induce it to implement cost-effective conservation activities. The Northwest Energy Coalition endorsed the program because it is structured in such a way that Idaho Power will need to show excellent performance in order to received incentive payments.

Net metering customers will continue to get retail rate

Case No. IPC-E-06-17, Order No. 30227

January 30, 2007

Net-metering customers of Idaho Power Company who generate their own electricity and sell their surplus back to the company will continue to be paid the full retail rate rather than a wholesale rate. However, an order issued by the commission allows the company to include power supply expenses associated with the net metering customers in its annual power cost adjustment (PCA) process for possible recovery from ratepayers.

Idaho Power has about 27 residential and small-business customers who offset their own power consumption by generating their own power with small hydro, wind or solar projects. Another 13 customers have pending requests for net-metering generation interconnects.

In August 2006, Idaho Power filed an application with the commission to pay net-metering residential and small business customers an amount equal to about 85 percent of the wholesale market rate for electricity rather than the full retail rate. In December, the company modified its application to leave the rate paid for excess generation the same. The final order issued by the commission leaves the rate the same, but grants Idaho Power's request to recover expenses associated with the net metering program through its annual power cost adjustment process. The order also grants the company's request to remove a financial impediment for customers in classes other than residential and small-businesses to participate in net metering by removing a requirement that those customers have a second meter.

In its original application, Idaho Power asserted that excess generation from residential and small-business net metering customers is "non-firm," or intermittent. Thus, those customers should be paid the same rate – a lower wholesale rate – as all sellers of non-firm energy. Under the current system of paying full retail rate for excess generation, Idaho Power said it does not recover its full costs of providing service to net metering customers and that those costs are shifted to the remaining residential and small-business customers who do not have net metering. Customers do get the full retail rate for all the energy that offsets their own consumption, but, the company believes that generation in excess of the customer's consumption should be viewed differently.

The commission said the amount of excess generation sold back to the company by net metering customers is not substantial enough to warrant a revision to the tariff. The cumulative capacity of existing net metering projects is 336 kilowatt-hours and the total amount paid for the projects' excess generation over the past 12 months was \$23,102. "If this increased substantially, it would be necessary to reconsider the pricing of excess generation. There is no need for that reassessment at this time," the commission said.

The commission cautioned potential net metering customers against relying on continuation of the current tariff when calculating their investment in net metering projects. "We must note that the net metering program price is a tariff rate. It is not a contract rate. As a tariff rate, it is subject to change," the commission said. "A persuasive argument could be made that net metering customers are being subsidized by other customers."

Rocky Mountain Power, CAPAI reach weatherization agreement

Case No. PAC-E-06-10, Order No. 30239

February 13, 2007

The Idaho Public Utilities Commission has accepted a settlement between PacifiCorp and the Community Action Partnership of Idaho (CAPAI) that expands the scope of weatherization activities and increases the utility's share of expenses to install weatherization measures in low-income households in southeast Idaho.

The settlement comes from an earlier settlement between the commission and various parties to PacifiCorp's recent rate case. PacifiCorp, which does business in eastern Idaho as Rocky Mountain Power, agreed to provide CAPAI an opportunity to contest the terms of Rocky Mountain's participation in low-income weatherization programs. In exchange, CAPAI agreed not to contest the rate settlement. CAPAI is a non-profit corporation consisting of six community action agencies that serve every county in Idaho to fight the causes and conditions of poverty.

Under the terms of this settlement, Rocky Mountain has agreed to expand the scope of allowed weatherization measures, more closely aligning them to the weatherization measures provided in the rest of the state. For example, Rocky Mountain did not reimburse for repairs related to weatherization, such as a leaky roof or a damaged window frame. Under the settlement, those expenses will now be reimbursed to the community action agencies based in Idaho Falls and Pocatello that do the weatherization.

The company also agreed to increase its maximum reimbursement from 50 percent of the total cost to 75 percent when matching federal grants are available. If federal grants are not available, Rocky Mountain will provide 100 percent reimbursement.

Rocky Mountain has weatherized more than 600 homes since 1988. Rocky Mountain's total funding for its weatherization is capped at \$150,000 per year. Under the terms of the settlement, that cap remains the same.

CAPAI has also agreed not to intervene in any proceeding with the intent of modifying the program further for the next two years. At the end of the two-year period, Rocky Mountain will submit to the commission and to CAPAI an evaluation of the program's results, particularly its cost-effectiveness.

The Low-Income Weatherization Program is intended to reduce electric consumption and monthly bills by increasing the efficiencies of low-income homes. The weatherization is provided at no charge to participating households.

Commission continues funding of weatherization program

Case No. IPC-E-07-09, Order No. 30350

June 26, 2007

Stage regulators have approved a joint application by Idaho Power Co. and the Community Action Partnership Association of Idaho (CAPAI) to extend a weatherization assistance program for low-income customers and non-profit organizations.

After Idaho Power's 2004 rate case, the Idaho Public Utilities Commission approved a request by CAPAI to increase the annual investment for weatherization from \$200,000 to \$1.2 million for the years 2004 to 2007. The commission said it would consider renewal of the Weatherization Assistance for Qualified Customers (WAQC) program in 2007 after reviewing reports of the program's progress.

During the last three years, the program has saved more than 6 million kilowatt-hours, according to commission staff. Staff also determined that the savings-to-investment ratio per home (including the cost of health and safety measures) is about \$2 for every \$1 spent. "The program has demonstrated that it is a cost-effective means of implementing conservation measures and promoting energy efficiency," the commission said.

According to annual reports filed by Idaho Power, the number of buildings weatherized under the program was 264 in 2004, 570 in 2005 and 540 in 2006.

AARP-Idaho and the Idaho Community Action Network filed comments in the case, both endorsing extension of the program.

Commission staff also recommended that Idaho Power use the weatherization program as a vehicle to deliver other conservation programs to qualifying customers such as compact fluorescent light (CFL) bulbs and efficient appliances. The commission adopted a staff recommendation that the company develop a tariff that would more easily allow community action agencies and the public to obtain information about how the program is operated. The tariff would include eligibility requirements, allowable energy conservation measures and a description of the program's structure.

Commission OKs new load control program

Case No. PAC-E-06-12, Order No. 30243

February 15, 2007

The Idaho Public Utilities Commission has approved a second Irrigation Load Control Program for customers of Rocky Mountain Power that could save up to 45 megawatts of demand on Rocky Mountain's system.

Under the program, eastern Idaho irrigators who volunteer to participate would get financial credit for allowing Rocky Mountain Power to interrupt service during times of peak demand. This program differs from an existing irrigation load control program in that the company can interrupt service remotely from a

central network server in Boise. Rather than service interruptions taking place on a scheduled basis – as is the case with the existing irrigation load control program – interruptions would be at the company’s discretion. The network server will communicate with customers, using either cell phone or e-mail technology to alert them of impending interruptions to service, or “dispatch events.”

The pilot program also differs from the existing program in that credits are yearly rather than on a monthly basis.

Rocky Mountain Power will allow eligible customers to enroll on a first-come, first-served basis.

Total curtailment per participating customer would be limited to no more than 65 hours during the 2007 irrigation season per customer. Dispatch events would occur anytime between 2 and 8 p.m., Mondays through Fridays during the irrigation season. Rocky Mountain Power will credit the bills of participating customers at the end of the irrigation season. Participants can opt out of a dispatch event up to five times during the 2007 irrigation season. If participants opt out more than twice, the credit paid to the participant will be reduced by the replacement cost of the energy during the dispatch event.

Commission says Avista pilot program should benefit all customers

Case No. AVU-E-07-04, Order No. 30365

July 11, 2007

State regulators have approved a pilot program by Avista Utilities that should reduce the need for the utility to buy power from the expensive wholesale market during peak demand times when energy is most expensive.

The Idaho Public Utilities Commission approved the two-year pilot that would enlist volunteer customers to agree to have programmable controllable thermostats attached to a number of their appliances, with air conditioning units given priority. The program is limited to the Sandpoint and Moscow areas, but could be expanded if needed to gain more participants.

At least four times during the year when electrical demand is at peak, Avista will declare a peak event during which the thermostats would be used to control the use of appliances in the homes of volunteer customers. Each of the peak events is expected to last for four hours, but can be extended to six hours depending on power price and conditions.

Avista estimates the pilot will cost \$123,000, but believes it will save at least \$150,000 in power costs during the peak-periods when the program is in place.

Incentives for customers to participate include upgraded equipment and their associated features they will receive from the utility. Customers opting in for a programmable thermostat will receive a thorough inspection of their heating, ventilating and air conditioning (HVAC) system. Customers with demand response switches will also receive an audit of all equipment controlled by the switch plus a \$10 a month credit during July, August, December, January and February.

Avista will evaluate the effectiveness of the program by examining energy savings, effectiveness of the technology, customer acceptance, and interaction of peak demand on the company's overall distribution system. The company will also present a final report to the commission. Commission staff acknowledged the proposed pilot is limited in scope, yet designed to obtain considerable information for a relatively modest investment.

The commission commended Avista for its continued efforts to develop cost-effective Demand Side Management (DSM) programs. Such programs are designed to curb electrical demand on the company's overall system, reducing the need for Avista to buy additional power during peak demand periods when it is most expensive. Such programs can even delay the need to build new power plants. "The proposed pilot programs, we find, should benefit all customers, both participants and non-participants," the commission said, resulting in lower customer bills, deferring the need for new supply sources and reducing the company's high-cost peak power needs.

Idaho endorses efficiency plan; Commissioner Smith co-chairs national effort September 7, 2007

The Idaho Public Utilities Commission, along with other Idaho agencies, is joining in a nationwide effort to enhance energy security and protect the environment by encouraging public and private entities to implement energy efficiency measures.

The commission, the office of Idaho Gov. C.L. "Butch" Otter, the Idaho Energy Division and the state Department of Environmental Quality are endorsing the recommendations of the National Action Plan for Energy Efficiency.

The aim of the national plan, co-chaired by Idaho Commissioner Marsha Smith and Jim Rogers, president of North Carolina-based Duke Energy, is to secure commitments from public and private entities in every state to reduce energy consumption.

The plan's recommendations, if fully implemented, could save Americans billions of dollars in energy bills over the next decade, contribute to energy security by reducing the nation's reliance on foreign oil and improve the environment through reduced greenhouse gas emissions.

"Conservation is the lowest-hanging fruit in the energy orchard, and it's our first priority in making Idaho and America more energy independent," Gov. Otter said. "Idaho has a great team in place, including the PUC, DEQ, the Energy Division, and other agencies, working together to address a range of energy-related issues from greenhouse gas emissions to ensuring the infrastructure is in place to more efficiently and cleanly meet tomorrow's needs," the governor said. "Taking part in this National Action Plan is another step in the right direction."

The plan, initiated under the leadership of the federal Department of Energy and the Environmental Protection Agency, was developed by a leadership group of more than 50 electric and gas utilities, utility

regulators, state agencies, large energy users, consumer advocates and environmental and energy efficiency organizations.

Idaho's Public Utilities Commission has already taken a number of steps to encourage energy efficiency in the state. "Energy efficiency is the cleanest, least cost energy available and can be obtained more quickly than other generation resources," said Commissioner Smith.

The commission, in cooperation with electric utilities, has implemented "demand-side management" programs that reduce demand on electric generators during peak operating times, often with the use of advanced metering technology. The commission has approved time-of-use metering, which allows residential and irrigation customers to shift their electrical use to non-peak times of the day in exchange for paying a lower electric rate. Residents can also volunteer to participate in a program that allows their electric utility to remotely control customers' air conditioning units during peak periods to reduce demand.

The commission, working with customer groups and utilities, recently doubled the funding for weatherization projects for qualifying homes. In cooperation with Idaho Power Co., the commission has authorized a pilot program that removes the financial disincentive to utilities caused when conservation programs reduce energy sales.

Energy efficiency measures like these reduce consumption while delaying and perhaps even preventing the need to build new power plants. "We need to make sure we've explored all the cost-effective energy efficiencies we can before we build additional electric generation sources," said Commissioner Paul Kjellander, president of the Idaho Public Utilities Commission.

The commission isn't the only state agency actively promoting energy efficiency. The Idaho Energy Division has for years promoted energy efficiency programs that reduce consumption. The Energy Star Homes Northwest program for site-built homes and the Northwest Energy Efficient Manufactured Homes program are both examples of new housing that reduces energy consumption by 30 percent over standard construction, according to Bob Hoppie, energy division administrator. "These are just two efforts the Energy Division is vigorously working on to support the National Action Plan," Hoppie said.

The state's Department of Environmental Quality has also formally endorsed the plan.

"Energy efficiency not only makes good economic sense, but also goes hand-in-hand with other statewide efforts to reduce air pollution, conserve water and reduce greenhouse gases," said Toni Hardesty, state DEQ director.

Rogers, the Duke Energy CEO who co-chairs with National Action Plan with Commissioner Smith, said the cheapest way to generate emissions-free power is improving energy efficiency. "The most environmentally sound, inexpensive and reliable power plant is the one we don't have to build because we've helped our customers save energy."

Other electric cases

Commission rejects Avimor agreement; Avimor appeals to Supreme Court
Case No. IPC-E-06-23, Order No. 30322
May 24, 2007

The Idaho Public Utilities Commission denied a Special Facilities Agreement between Idaho Power Co. and Avimor, LLC, the developer for a major housing project north of Boise.

The agreement called for Avimor to advance Idaho Power \$4.3 million to allow the utility to build 3.4 miles of a 138-kV transmission line and a substation. Avimor would receive a refund of its entire \$4.3 million if, within 10 years, 685 permanent residential services had been connected or electrical demand at the development exceeded 6,850 kilowatts.

The commission said the agreement creates an undue risk that existing customers will have to pay for the transmission line and substation. "The risk needs to remain with the developer," the commission said, particularly since the expanded transmission and distribution is necessitated solely by the Avimor project.

Idaho Power historically has not required an advance from residential developers to extend transmission and distribution facilities, but the company said the agreement was needed here because of the speculative nature of the development.

The commission agreed that an advance is necessary, but the amount Idaho Power would eventually have to refund Avimor, at about \$6,277 per customer, was too high. The amount currently included in base rates for transmission and investment is \$350 per customer. For newer developments, the customer investment is about \$1,000. All the refunds paid by Idaho Power to Avimor would be considered investment and ultimately included in the calculation of customer rates. That led to concern by the commission that the difference between the investment included in current rates and the estimated investment for the Avimor facilities would require a subsidy by existing customers, causing upward pressure on rates.

Noting those concerns, Avimor revised its application to allow it to receive refunds of \$3,900 per customer, requiring 1,103 customers to connect to the facilities within 10 years before it received a full refund from Idaho.

Even Avimor's revised application was still far above the amount currently included as investment in customer rates, the commission said. The commission said the per customer refund amount should be \$1,000 rather than \$3,900. "At that rate, 4,300 customer connections places a greater risk on the developer, where it properly belongs, for the success of its project," the commission said.

If 4,300 customers are not connected within 10 years, Avimor will not receive a full refund of transmission and substation costs. The commission further stated that Idaho Power collect contributions

from other developers who may connect to the facilities. The commission also rejected a proposal by Avimor that interest accrue on the unrefunded amounts paid by Avimor.

The commission commended Avimor for incorporating energy efficiency measures into the community development. Avimor plans to construct 585 homes in the first phase of the project that meet standards 30 percent more energy efficient than traditional construction. Further, it plans to build a treatment plant capable of recapturing 300,000 gallons of wastewater for irrigation purposes. "Avimor correctly notes that the commission has, for a number of years, encouraged Idaho Power to implement energy conservation programs, and the Avimor project as planned is consistent with the commission's objectives," the commission said.

Note: Avimor later petitioned the commission for reconsideration. The commission denied reconsideration. In September, Avimor filed an appeal with the State Supreme Court. That case was still pending at the printing of this report.

Commission wants more refinement of Avista disconnect plan

Case No. AVU-E-07-09, Order No. 30471
December 5, 2007

The Idaho Public Utilities Commission is looking for "further development and refinement" of a proposed pilot program that would allow Avista Utilities to disconnect and reconnect power to customers from a remote location. The commission wants Avista and parties who have filed comments in the case to conduct workshops and then present a refined program for commission consideration.

Customer groups filing comments in the case fear remote disconnection of customers who are behind in payments could result in increased disconnections and threaten the health and safety of some customers.

Avista, which serves about 115,000 Idaho customers from Grangeville north to the Canadian border, proposes to install about 250 remote disconnect collars in rural areas and about 350 wireless meter devices in urban areas of its northern Idaho territory. Customers selected for the one-year pilot program would be those who have had multiple disconnects, are located in rural areas or otherwise occupy premises where Avista employees may be at risk for entering customer property and manually performing disconnects or reconnects.

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.

However, AARP Idaho said remote disconnection might increase the number of disconnections, impacting health and safety, particularly if customers are disconnected during extreme weather conditions. Currently, a utility employee visits a home before a disconnection, giving customers a final opportunity to pay. The home visit also provides an opportunity for the utility employee to observe

possible health and safety dangers, such as a customer using a respirator or other medical devices requiring electric service. AARP Idaho said Avista does not specify how customers would be selected for the pilot program and further stated that low-income seniors, ill and disabled customers and families with young children should not be included.

Another customer group, that Community Action Partnership of Idaho, said the program may benefit shareholders, but diminishes the level of service provided customers. CAPAI also expressed concern about a dramatic increase in disconnects and the loss of an opportunity to make a final payment before disconnection. CAPAI said the pilot might set a precedent for other utilities that don't have as good a customer service record as Avista.

Comments filed by commission staff recommend approval of the program as part of its effort to encourage all utilities to use "smart meter" technology. But commission staff did express concern about how customers would be selected. 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.

Whether the pilot is approved or not, Avista and all regulated utilities must abide by nearly all 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 rule waived under the pilot is the one requiring a utility employee to knock on the customer door to provide a final opportunity to make a payment.

This case was still open at the publication of this report.

PUC allows transfer of Rocky Mountain Power customers to Fall River
Case No. PAC-E-07-12, Order No. 30381
July 26, 2007

About 72 households in Teton County that have been electrical customers of Rocky Mountain Power became customers of Fall River Rural Electric Cooperative, Inc. on Aug 1.

The commission approved a petition by Rocky Mountain Power and Fall River Rural Electric to approve the transfer of about half of Rocky Mountain's customers in Teton County to Fall River. Growth in the Teton County basin is increasing the potential for duplication of facilities, which presents operational issues for both companies.

The transfer includes not only customers on the west side of the valley, but also equipment such as poles and transformers from Rocky Mountain to Fall River, which is headquartered in Ashton.

The transfer does not immediately impact rates because Fall River has agreed to serve the transferred customers under Rocky Mountain's rate structure for five years. Further, about 22 customers who participated in Rocky Mountain's Time-of-Day rate structure will be billed under the same structure by Fall River. The Time-of-Day program gives customers reduced rates for shifting electrical use away from peak-use times of the day.

Idaho statutes require that the commission determine the following when considering the sale or transfer of any public utility property: 1) the transaction is consistent with the public interest, 2) rates will not increase because of the transaction and 3) the buyer has the intent and financial ability to operate the property in the public service.

Commission staff said reliability would improve for all customers with the transfer and that Fall River, with 13,000 customers in Idaho, Montana and Wyoming, has been providing reliable service to its customers since 1938. Because Fall River is a non-profit electric cooperative, the commission does not regulate it. However, Rocky Mountain Power is an investor-owned utility and is regulated by the commission. It has about 67,000 customers in southeastern Idaho.

Commission staff reviewed the application to ensure it complies with the state's Electric Suppliers Stabilization Act which is to discourage duplication of facilities, prohibit one utility from "pirating" customers from another, stabilize service territories and promote harmony between electric suppliers.

SERVICE AREAS OF INVESTOR OWNED ELECTRIC UTILITIES IN IDAHO

