ELECTRICAL POWER IN IDAHO

Idaho Power Company

<u>2014 Average Number of Customers/Avg. Revenue/kwh*</u>
411,689 Residential Customers/$0.1007
79,248 Commercial Customers/$0.0769
111 Industrial Customers/$0.0564

Avista Utilities

<u>2014 Average Number of Customers/Avg. Revenue/kwh*</u>
108,571 Residential Customers/$0.0921
16,937 Commercial Customers/$0.0867
455 Industrial Customers/$0.0555

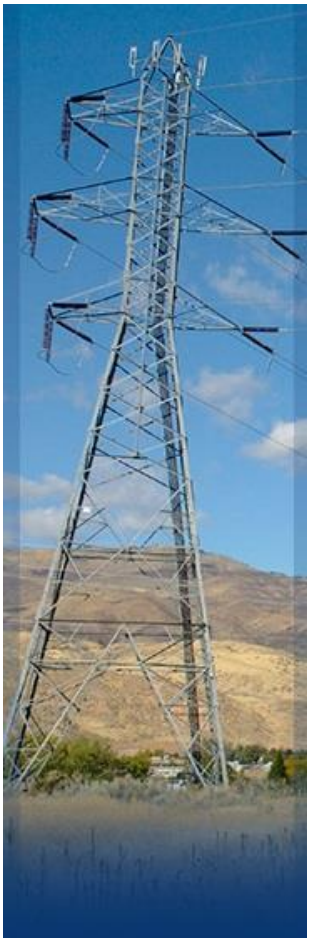
Rocky Mountain Power

<u>2014 Average Number of Customers/Avg. Revenue/kwh*</u>
PacifiCorp/Rocky Mountain Power
59,974 Residential Customers/$0.1102
8,246 Commercial Customers/$0.0886
5,534 Industrial Customers/$0.0613

*Computed from data available in FERC Form 1 Annual Reports dated June 30, 2015.

ELECTRIC

Avista Rate Case



Proposed settlement significantly reduces Avista rate electric, natural gas rate increase request

Case No. AVU-E-15-05, AVU-G-15-01, Order No

October 26, 2015 –Parties to an Avista Utilities rate case are proposing a settlement that reduces the Spokane-based utility's requested electric rate increase from 10.3% over two years to 0.7% in one year and its requested gas rate increase from 6.8% over two years to a one-year increase of 3.5%. All parties to the case, including Avista, are asking the commission to approve the settlement, with rates proposed change on Jan. 1. 2016. Avista serves customers in northern Idaho.

While base electric and gas rates, which reflect Avista's fixed costs, would increase Jan. 1, 2016, under the proposed settlement, customers are getting substantial reductions to the variable portion of their rates that more than offset the base rate increases. On the electric side, the annual Power Cost Adjustment reduced electric rates by 3.5% on Oct. 1. On the gas side, the annual Purchases Gas Cost Adjustment will reduce gas rates by 14.5% on Nov. 1. However, base rate changes are permanent, while the variable PGA and PCA adjustments either increase or decrease rates yearly.

On June 1, Avista filed an application to increase electric rates by 5.2% in 2016 and 5.1% in 2017 and natural gas rates by 4.5% in 2016 and 2.2% in 2017. Under the original proposal, Avista's annual increase in revenue would have been $13.2 million on the electric side. The proposed settlement reduces that to $1.7 million. Annual gas revenues would have increased by $3.2, with the settlement proposing $2.5 million.

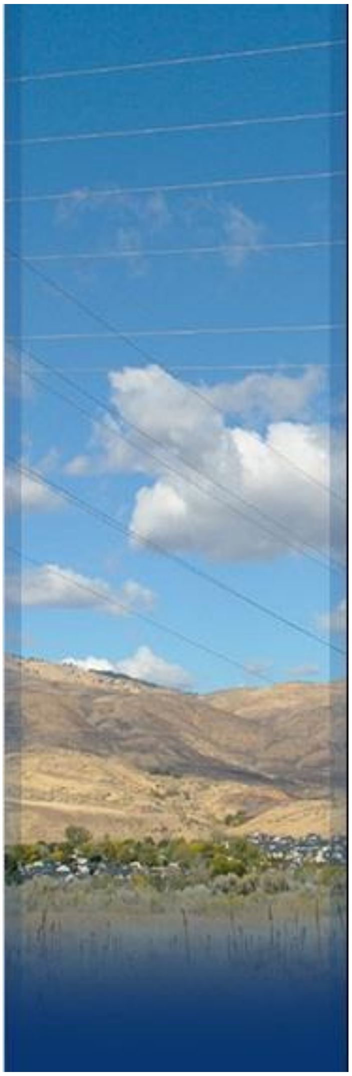
Parties signing the settlement include Avista, commission staff, the Idaho Conservation League, Snake River Alliance, Clearwater Paper Corporation, Idaho Forest Group LLC and the Community Action Partnership Association of Idaho, which represents primarily customers on low- and fixed-incomes.

While the settlement proposes reductions to Avista's annual revenue requirement, it does allow Avista to establish an annual rate adjustment called the Fixed Cost Adjustment (FCA). The FCA will allow the company to recover fixed costs of doing business when electricity or natural gas sales decline due to changes in conservation, weather or the economy. The mechanism removes the disincentive for the company to invest in and promote energy efficiency programs.

Under the FCA, the company's natural gas and electric revenues would be adjusted monthly to reflect revenues based on the number of customers rather than kilowatt-hour and therm sales. The yearly adjustment will be either a surcharge or rebate to customers. The FCA would have an initial term of three years and will be reviewed to determine whether the adjustment should continue.

These are some of the major revenue reductions from Avista's original request proposed by the settlement:

- Leaving expense related to the Palouse Wind Project in the annual Power Cost Adjustment mechanism rather than shifting it to base rates, reducing annual base rate revenue requirement by $3.5 million.
- Shifting expense related to an upgrade of the Nine Mile Hydroelectric project from 2015 to 2016, reducing revenue requirement by $3.34 million.
- Establishing a 9.5% Return on Equity, rather than the 9.9% proposed by Avista, reducing annual revenue requirement by $2.44 million.
- Spreading the cost of Avista's new customer information and billing service called Project Compass over four years rather than two years, reducing revenue requirement by $669,000.
- Reducing various capital additions that bring revenue requirement down by $548,000.
- Removing projected 2016 expense related to information services and technology to reduce revenue requirement by $521,000.
- Removing 2016 non-executive labor expense to reduce revenue requirement by $385,000 and removing incentives this year for company officers to reduce annual revenue requirement by $100,000.



Avista will award grants for commercial solar applications

Case No. AVU-E-14-10, Order No. 33218

February 4, 2015 – The commission approved an Avista Utilities application to award grants for rooftop solar applications on small commercial buildings in its northern Idaho territory.

Avista has a $200,000 surplus in its "Buck-a-Block" renewable energy tariff that will accrue an additional $150,000 to $200,000 by the end of 2016. "Buck-a-Block," in place since 2002, allows Avista customers who want to buy renewable power from regional wind and solar sources to buy in blocks of 300 kilowatt-hours at $1 per block.

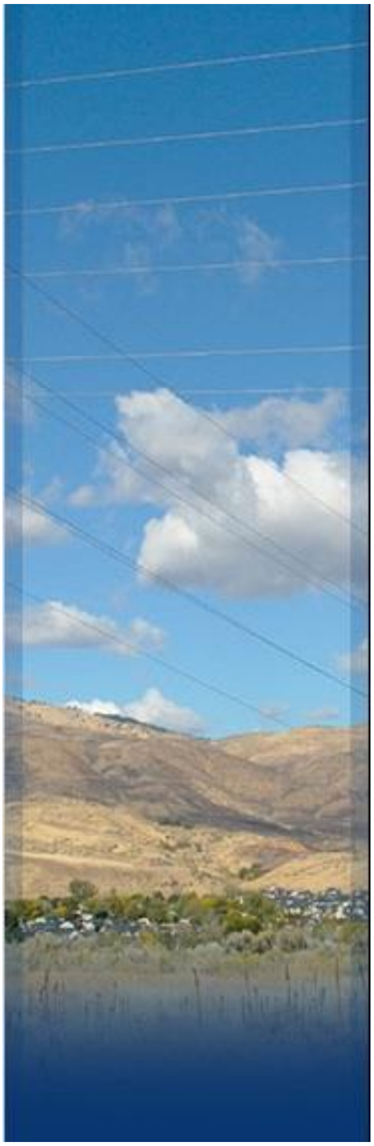
During 2013, about 3,500 Avista customers in Washington and northern Idaho purchased nearly 227,000 blocks or 68,000 megawatt-hours. However, due to the availability of low-cost renewable energy credits in recent years and a plateau in the number of Avista customers signing up for the program, there is a surplus of about $200,000 in the Buck-a-Block tariff.

Avista proposed to use that surplus to award grants for rooftop solar installations of 20 kilowatts or smaller on commercial buildings. Successful grant recipients would agree to allow their installation to be made available for educating building occupants and members of the community on the benefits of both solar energy generation and Avista's Buck-a-Block program. Preference would be given to school buildings and other public buildings where the visibility of the installation will have the greatest impact for both educational purposes and solar energy generation.

Commission staff reviewed the proposal to determine its impact on Buck-A-Block participants and on other ratepayers. Staff expressed concern about uncollected fixed costs from program participants that would be shifted to other customers.

However, staff determined that the level of uncollected fixed costs associated with this program is so low that it will have little impact on customer rates. Staff recommended that the commission monitor the growth of the program.

Staff was also concerned that a disproportionate amount of the surplus funds would go to Washington customers of Avista because the cost of solar panels is as much as three times higher in that state than in other places.



Avista expenses determined prudent; utility exceeds electric, gas conservation goals

Case No. AVU-E-14-07 and AVU-G-14-02, Order No. 33126

Jan. 30, 2015 – The commission determined that $7.7 million Avista Utilities spent on electric and natural gas efficiency programs during 2013 was prudently incurred.

Money spent on electric and gas conservation programs must be shown to be prudently incurred in order to be funded by the Energy Efficiency Rider paid by Avista's customers. Residential customers currently pay 0.245 cents per kilowatt-hour for the programs. The commission's prudency review does not impact rates.

All three of Idaho's major investor-owned utilities have "efficiency riders" that pay for programs to incent either the efficient use of electricity or reduce demand on a utility's generation system. The programs must pass multiple cost efficiency tests that demonstrate that the savings realized are greater than the programs' costs. Further, the programs must benefit all customers, not just those who participate in them.

Avista claims it energy efficiency savings for 2013 were 25,899 megawatt-hours, well over its target of 19,009 MWh. Reduced demand on its system is 122 average megawatts. Company-sponsored conservation is reducing retail loads by 10.6%, Avista claims. This is the fourth consecutive year Avista exceeded its Conservation Potential Assessment for electric savings. Its gas savings are 51,722 terms.

Commission staff conducted a review of Avista's programs and expenditures. The commission commended Avista for exceeding its goals. "The commission urges the company to continue this favorable trend and even improve upon its commitment to the implementation of cost-effective demand-side management programs," the commission said.

Avista PCA results in 3.5% reduction for electric customers

Case No. AVU-E-15-07

October 5, 2015 – The variable portion of Avista Utilities' electric rates decreased by an average 3.5 percent effective October 1.

Avista electric rates are adjusted up or down every year on Oct. 1 depending on the previous year's weather and market conditions and other variable factors. Because variable rate impacts cannot be predicted, rates are adjusted annually through the Power Cost Adjustment (PCA) mechanism to match what customers paid in the PCA account with actual expense.

Avista's variable power supply costs decreased by about $1.2 million from July 1, 2014, through June 30, 2015. Most of that – $820,000 – came from lower payments owed to Clearwater Paper, which owns a cogeneration plant that sells power to Avista. Another $400,000 credited customers is the result of a settlement between electric utilities and the Bonneville Power Administration.

With the Oct. 1 adjustment, the PCA changes from a surcharge of 0.252 cents per kilowatt-hour to a rebate of 0.032 cents per kWh. For a residential customer who uses the company's average of 929 kWh per month, the reduction is about $2.64 per month.

Result of two annual rate adjustments is net decrease for Idaho Power customers

Case No. IPC-E-15-05, Order No. 33302; Case No. IPC-E-15-14, Order No. 33306

May 28, 2015 – Rates for residential customers of Idaho Power Company decrease slightly on June 1 due to annual updates of two rate adjustments approved by the Idaho Public Utilities Commission.

The annual Fixed Cost Adjustment (FCA) increases rates by 0.35 percent, but that is offset by a slightly more than 1 percent decrease in the annual Power Cost Adjustment (PCA). The FCA increase is about 36 cents per month for a residential customer who uses the customer average of 1,050 kilowatt-hours per month. The PCA decrease is about 58 cents per month for a residential customer.

Power Cost Adjustment

Since 1993, the PCA mechanism allows Idaho Power to adjust rates up or down to reflect that portion of costs that change every year due to factors largely beyond the company's control. Because about half of Idaho Power's generation is from hydroelectric facilities, Idaho Power's actual cost of providing electricity varies depending on changes in Snake River streamflows. Other costs that vary each year are the market price of power, fuel costs, transmission costs for purchased power and the revenue it earns from selling surplus power.

Idaho Power's forecasted net power supply expense is $384.4 million, $42.7 million higher than the $305.7 million of power supply expense already included in base rates, necessitating a surcharge. However, the total amount of power supply expense above base rates is lower than that collected in last year's PCA resulting in a smaller-sized surcharge and, thus, a slight reduction to customers.

Actual hydro generation (3.4 million acre-feet) is about 7 percent lower than forecast (3.6 million acre-feet.) Less hydro generation forces the company to use more expensive generation sources, driving up power supply expense. That expense is reduced by Idaho Power's sale of surplus power on the market, but revenue from off-system sales continues to decline. Because of lower prices on the wholesale energy market, Idaho Power is forecasting only $39 million in sales, down from the $51.7 million included in base rates. However, the loss in off-system sales is somewhat offset by lower priced purchases from the market and reductions in coal and gas production costs.

The PCA rate effective June 1 will be about 0.53 cents per kilowatt-hour, less than the current rate of 0.73 cents per kWh. (The approximate one-half cent per kWh PCA rate is a relatively small component of overall rates. A customer who uses the company's average of 1050 kWh per month now pays an energy rate of about 8.2 cents per kWh during the non-summer months and 9 cents during the summer months.)

To mitigate the surcharge even further, Idaho Power proposed to apply $8 million in revenue sharing to customers and to credit customers $4 million in additional energy efficiency rider funds collected last year.

As part of a settlement to a 2011 base rate case, the company agreed to share revenue with customers if it exceeded a 10 percent Return on Equity. Any earnings greater than 10 percent ROE up to and including 10.5 percent would be split 50-50 with customers to be applied against the PCA. Earnings above 10.5 percent will be shared 75 percent with customers and 25 percent for the company. Those earnings are applied against what customers would otherwise be paying to fund the company's pension balancing account.

Idaho Power's 2014 year-end ROE was 11.19 percent, meaning customers will receive a benefit of $24.7 million. About $8 million is applied as a rate credit passed through the PCA, while the remaining $16.7 million is used to offset the pension balancing account.

The FCA is designed to ensure Idaho Power recovers its fixed costs of delivering energy even when energy sales and revenue decline due to reduced consumption. Before the FCA, Idaho Power had a financial disincentive to invest in energy efficiency programs because it lost revenue as consumption declined. Even though consumption may decline, fixed costs to serve customers do not. To remove that disincentive, the Fixed Cost Adjustment was created to allow the utility to recoup its fixed costs.

If actual fixed costs recovered from customers are less than the fixed costs authorized in the most recent rate case, residential and small-commercial customers get a surcharge. If the company collects more in fixed costs than authorized by the commission, customers get a credit.

During 2014, Idaho Power under-collected fixed costs of serving customers by $16.88 million. About $14.9 million of that is already collected in the FCA. To recover the additional $1.96 million, the commission approved an increase the Fixed Cost Adjustment from 0.29 cents per kWh to 0.326 cents per kWh for residential customers and from 0.37 cents per kWh to 0.41 cents per kWh for small commercial customers. In a separate case, the commission adopted a settlement to a docket opened last year to evaluate the effectiveness of the FCA.

Beginning this year, Idaho Power will modify the way it calculates the FCA deferral by replacing an average of weather-normalized billed sales with actual billed sales.

Parties to the settlement also agreed to further clarify how a 3% cap on annual FCA increases should be calculated. All parties agreed that without the FCA, current rate design creates a financial disincentive for Idaho Power to pursue cost-effective energy efficiency. However, they also stated that the commission could pursue a modified rate design for residential and small commercial customers to address this issue, in lieu of an FCA mechanism. Possible rate design changes could include reduced energy charges but higher monthly service charges or the introduction of demand charges.

IPUC approves Idaho Power agreement to continue participation in regional conservation effort

Case No. IPC-E-14-38, Order No. 33210

Jan. 21, 2015 – The Commission approved an Idaho Power Company proposal to invest $13.45 million in energy efficiency programs operated by the Northwest Energy Efficiency Alliance (NEEA), but agreed with commission staff findings that the utility is not doing enough to make customers aware of energy efficiency programs.

The $13.45 million investment by Idaho Power covers five years, from 2015-19, and is down from the $16.5 million the utility invested in NEEA during 2010-14.

NEEA is a non-profit organization that seeks to maximize energy efficiency in four Northwest states through the adoption of energy efficient products, services and practices. NEEA is funded by the Energy Trust of Oregon, the Bonneville Power Administration and by electric utilities in Washington, Oregon, Idaho and Montana. Idaho Power's investment represents about 9 percent of NEEA's total budget.

From 1997-2014, NEEA delivered 1,024 average megawatts of regional energy savings. Idaho Power's portion of NEEA-related savings during the same period was 28.2 aMW.

Idaho Power had notified NEEA that once the 2010-14 funding cycle ended, its participation would end. Idaho Power claimed the NEEA funding model duplicated services that it could perform on its own at a lower cost or more effectively.

Since then, however, NEEA and Idaho Power reached an agreement that allows Idaho Power to opt out of some NEEA programs that Idaho Power said were duplicative or did not directly benefit customers, while still participating in others.

The 2015-19 plan agreed upon by Idaho Power and NEEA is customized to better meet its customers' needs, Idaho Power said. The plan includes funding for continued research at the University of Idaho Integrated Design Lab and market transformation efforts aimed at acquiring energy efficient lighting, appliances and building materials in the residential, commercial and industrial sectors.

Of the four optional NEEA programs, Idaho Power chose to participate in only one, a program that targets commercial lighting contractors, training resources and utility programs to accelerate market adoption of advanced lighting practices.

The company chose to opt out of NEEA's Marketing and Stakeholder Support program which, commission staff said, "leaves Idaho Power responsible for creating all marketing, such as website development, press releases, consumer awareness campaigns" and other promotions. The commission said it expects Idaho Power to bolster its marketing and customer awareness by using savings from its decreased investment in NEEA.

The agreement does not change customer rates because Idaho Power's investment in NEEA energy efficiency programs is funded by a portion of the Energy Efficiency Rider on customer bills, currently set at 4% of a customer's monthly billed amount. However, before investment can be included in the rider, the commission will conduct a prudency review of the programs after the 2015-19 funding cycle to ensure "customers received a sufficient benefit," from Idaho Power's participation. Further, Idaho Power and NEEA's agreement holds NEEA accountable for delivering on its projected energy savings. Under the agreement, NEEA will hire an independent CPA firm to complete an annual financial audit and internal control review.

NEEA's business plan for the entire region is to deliver 145 aMW of energy savings in the four states from 2015-19, with a planned expenditure of between $145 million and $169 million. The total resource cost for NEEA programs is equal to are less than 3.5 cents per kilowatt-hour, considerably less than energy from most other sources

Commission OKs Idaho Power proposal to operate its own demand response program

Case No. IPC-E-15-03, Order No. 33292

May 13, 2015 – The Commission agreed to allow Idaho Power Company to operate its own energy demand reduction program for its large commercial and industrial customers.

Idaho Power maintains it can operate a program at less cost and with better or equal results than has the third-party vendor that has been operating the program since 2009. The "Flex Peak" program, previously operated by EnerNoc Inc., provided financial incentive to large commercial and industrial customers to curtail their energy use during peak-use hours of the summer months.

The Commission granted Idaho Power authority to operate its own program beginning this summer. "The commission strongly supports the use of commercial and industrial demand-response programs," the commission said. "And while EnerNoc's program was robust and cost-effective, customers will benefit if the company (Idaho Power) can deliver similarly reliable demand response at the same or less cost."

Now is a good time to let Idaho Power try its own program since the utility is not anticipating capacity deficits for the next few years, the commission said.

Under Idaho Power's program, the utility will call at least three "dispatch events" between June 15 and August 15, notifying volunteer customers on or about two hours in advance that they will need to reduce or curtail their energy use. The dispatch events will be during peak-use hours when demand on Idaho Power's system is the greatest. Those hours are typically between 2 p.m. and 8 p.m. on weekdays, excluding holidays. Each dispatch event will last between two and four hours, but no more than 15 hours per week or 60 hours per summer season. Idaho Power proposes to provide incentive payments to customers who agree to participate. The utility says operating Flex Peak internally will cost from $1.1 million up to $1.4 million if the entire 35 megawatts of potential savings were dispatched for the maximum allowed 60 hours. Costs under the EnerNoc program were about $2 million.

Idaho Power said savings from internal operation of Flex Peak will be passed directly to customers. Further, all customers benefit when Idaho Power does not have to buy or generate as much power from other more costly sources during peak-use hours when power is the most expensive.

The commission noted the concerns expressed by commission staff, the Industrial Customers of Idaho Power and the Idaho Conservation League about Idaho Power operating its own program. Consequently, it directed Idaho Power to file a report within one year detailing its experience running the program, cost-and-benefit comparisons to those achieved under EnerNoc, participant performance and any proposed changes to further improve the program. The company will also file an annual end-of-season report that will specify, among other items, number of participants, number of megawatts of demand response achieved and a detailed cost analysis.

Idaho Power also offers demand-response programs to residential and irrigation customers. According to Idaho Power, the cost of operating all its demand response programs in 2014 was $10.6 million, but the value accrued to the company and its customers as a result of the reduced demand was $16.7 million. Idaho Power plans at least 390 MWs of demand reduction from all its programs during 2015.

Idaho Power, Simplot contract is approved

Case No. IPC-E-15-13, Order No. 33303

May 22, 2015 – The Commission approved an Idaho Power Company special contract with J.R. Simplot Company's new Caldwell plant.

Until recently, the Caldwell plant was under a tariff rate (rather than a special contract) for Large Power Service customers. But Simplot's new Caldwell plant, which replaces Simplot facilities in Aberdeen, Nampa and Caldwell, is anticipated to exceed the maximum amount of demand – 20,000 kilowatts – that qualifies for the Large Power Service rate. Customers with demand larger than 20,000 kW must negotiate a special contract with the utility.

Idaho Power and Simplot have been negotiating a proposed contract since spring 2013. In late 2013, Idaho Power asked the commission to resolve some contract issues where the parties had reached an impasse. Those issues included liability provisions and Simplot's contention that Idaho Power was using an outdated formula to determine Simplot's rate.

The commission directed the parties to renegotiate the liability provisions and said a rate could be determined by using Idaho Power's most recent cost-of-service study as a starting point for negotiation. The company agreed to do so and the parties reached agreement. "We appreciate the parties' efforts in reaching an agreement consistent with guidance provided by the commission," the commission said.

The contract, which becomes effective June 1, requires Idaho Power to initially provide 25,000 kW per month. During the first year of the contract, Simplot may increase or decrease its contract demand so long as the changes for the year collectively do not exceed 10,000 kW, absent company agreement. After one year, Simplot may increase or decrease its monthly contract demand in 1,000 kW increments so long as it does not change contract demand by more than 15,000 kW in any 12-month period.

Rates for special contract customers must take into account Idaho Power's existing operational conditions and the impact new load may have on the utility's generation and transmission system. Because the new Caldwell facility consolidates load previously used at the Aberdeen, Nampa and old Caldwell facilities, the contract rates will recover the cost it incurs to serve Simplot while also limiting upward rate pressure on other customer classes.

Commission OKs Idaho Power efficiency program expense

Case No. IPC-E-15-06, Order No. 33365

August 31, 2015 – The Commission determined that Idaho Power Company's $33.5 million investment in energy efficiency and demand-response programs during 2014 was prudently incurred. The determination does not impact rates.

The efficiency programs are funded through a 4 percent Energy Efficiency Rider that appears on customer bills. The demand-response programs are included in the annual Power Cost Adjustment (PCA), listed on bills as the Annual Adjustment Mechanism.

Idaho Power’s energy savings rebounded significantly in 2014, surpassing 2013 numbers by 33 percent, more than exceeding the company’s target. Idaho Power offers 18 energy efficiency programs and three demand reduction programs. (An energy-efficiency program is one in which less energy is used to perform the same function. A demand-reduction program is one that shifts consumption to non-peak times of the day, reducing demand on a utility’s generation system.)

About $25.5 million of the total $33.5 million investment is related to energy efficiency and is recovered through the 4 percent rider. The remaining $8 million includes demand reduction incentive payments to program participants and is recovered through the PCA.

Energy efficiency programs resulted in 118,670 megawatt-hours of savings. That doesn’t include savings realized from Idaho Power’s participation in the Northwest Energy Efficiency Alliance’s market transformation initiatives. That resulted in another 20,000 MWh saved in Idaho Power’s service territory.

The company rolled out several new programs in 2014 including a Home Energy Audits marketing and education program and the distribution of residential clothes lines. It also expanded its successful Shade Tree program. Other energy efficiency programs include offering rebates to customers for using heating and cooling efficiencies and energy-efficient lighting and appliances. Demand reduction programs provide financial incentives to residential air conditioning, large commercial and industrial customers and irrigators to shift or curtail consumption to off-peak periods. These programs reduced demand by 378 megawatts, saving customers about $6.5 million. All the programs must pass cost-effectiveness tests to ensure that their cost does not exceed the benefit to customers.
In other issues related to the case:

- The Industrial Customers of Idaho Power expressed concern about a $9.8 million surplus in the Energy Efficiency Rider account that could grow to $15 million by the end of this year. The Snake River Alliance argued that reducing the 4 percent rider now as a response to the surplus would be premature because room exists to improve and expand existing DSM programs. The commission declined to reduce the rider at this time, but asked that all parties continue to monitor and rider balance and apprise it of positive or negative trends. The funds in the rider account cannot be used for any other purpose than expense related to energy efficiency and demand-side reduction.

- The commission encouraged Idaho Power to ensure that documentation requirements for customers who sign up for the programs not become so burdensome that they discourage participation.

- Both commission staff and the Idaho Conservation League said Idaho Power should be counting the including reduced transmission and distribution investment when it calculates the benefits of its DSM program. Idaho Power claims its investigation into that issue is ongoing.

Commission staff commended the company for improving its DSM marketing efforts through television, radio, Facebook and Pandora advertising and other means. Staff said Idaho Power should further improve its marketing by creating a branded campaign similar to those offered by Avista and Rocky Mountain Power.

However, the commission said Idaho Power exceeded its targets and, therefore, did not direct the company to incur additional marketing costs.

Commission approves one-year energy sales agreement between Idaho Power and Simplot's Pocatello plant

Case No. IPC-E-15-02, Order No. 33240

March 4, 2015 – State regulators approved an Idaho Power Company sales agreement with a J.R. Simplot company-owned cogeneration project at Simplot's Pocatello plant.

Cogeneration (also known as "combined heat and power" or CHP) produces power from the heat or steam that is the byproduct of a manufacturing process. The cogeneration plant at Simplot's fertilizer plant near Pocatello can produce up to 15.9 megawatts of electricity, but the contact is for 10 average megawatts per month.

The cogeneration plant is a qualifying facility under the provisions of the federal Public Utility Regulatory Policies Act of 1978. PURPA requires regulated utilities to buy energy from qualifying renewable generation projects at rates established by state commissions. The rate to be paid qualifying facilities is called an "avoided-cost rate," because it is based on the cost the utility avoids by not having to generate the energy itself or buy it from another source. The commission must ensure the avoided-cost rate is reasonable for utility customers because the price utilities pay to qualifying small-power producers is included in customer rates.

The Commission approved the company's proposed a rate of $52.72 per megawatt-hour to be paid Simplot during 2015 and $52.28 per MWh in 2016. The rate varies according to heavier and lighter load hours of the day and seasons of the year. The agreement is for one year.

Parties propose settlement to Rocky Mountain Energy Cost Adjustment Mechanism

Proposed settlement avoids base rate case filing

Case No. PAC-E-15-09

Oct. 28, 2015 – Staff to the Idaho Public Utilities Commission, Rocky Mountain Power and other parties are proposing a settlement to a Rocky Mountain company request to transfer some variable power supply expense into permanent base rates. The settlement had not been approved by the time this report was prepared.

The proposed settlement would increase base rates about 3.9% in 2016, but customers would notice a reduction of near the same size when the company files its annual Energy Cost Adjustment Mechanism (ECAM) to be effective in 2017.

The settlement replaces a base rate case the company would have filed this year and also includes a stay-out provision that prevents another base rate increase until Jan 1, 2018 at the earliest.

Under the proposed settlement, a residential customer who uses the average 801 kilowatt-hours per month would pay about $2.35 more each month. Rocky Mountain Power serves customers in eastern Idaho.

There are two primary components of customer rates. The base rate covers fixed costs that rarely change from year to year, while the ECAM includes expenses that vary each year depending on weather, fuel costs and wholesale market prices. If variable expense is less than that already included in rates, customers receive a credit. If variable expenses are greater than that already included in rates, customers are assessed a one-year surcharge.

The settlement proposes to shift $10.2 million of expense currently collected through the ECAM into base rates. About $6.5 million of that expense is related to revenue the company no longer receives from the trading of Renewable Energy Certificates (RECs). However, customers will be credited about that same amount when the company files its ECAM in 2017. Another $3.2 million is power supply expense for generation fuel and buying/selling power.

The settlement also changes the way the yearly ECAM is calculated, measuring it on a dollar-per-megawatt hour basis using load at the meter rather than load at the generator.

Rocky Mountain's annual power supply costs increase, resulting in 1.8% increase to most customers

Case No. PAC-E-15-01, Order No. 33265

April 2, 2015 – Rates for most customers of Rocky Mountain Power will increase by an average of 1.8% as a result of the utility's annual Energy Cost Adjustment Mechanism (ECAM). Rocky Mountain Power serves about 73,000 customers in eastern Idaho. According to the company's calculations, the increase for an average residential customer is about $1.70 per month. Rates for the company's two large industrial customers, Monsanto and Agrium, Inc., increase by about 8 percent.

The ECAM, which takes effect every April 1, accounts for the difference between the utility's actual power supply costs, which vary from year to year, and the amount of power supply costs already included in customer rates.

Most of the expense an electric utility incurs to provide power supply to its customers is included in base rates. However, the expense required to provide power to customers varies each year due to a number of factors including wholesale market prices for electricity and natural gas, transportation expense and expiration of older, lower-price contracts with energy suppliers.

Because these variable expenses can never be precisely forecast, the ECAM allows Rocky Mountain Power to make a one-year adjustment every April 1 to capture the difference between actual expense and that included in base rates. The adjustment is a one-year increase to customers if power supply costs are higher than the amount already included in base rates or a one-year decrease if power supply costs are lower. Since the ECAM went into effect in 2010, there have been two increases, one decrease and two years of no change in rates.

Rocky Mountain Power's earnings are not impacted by the ECAM because all the money collected from the ECAM must go directly to pay power supply expense and cannot be used for any other purpose such as increased salaries or dividends to shareholders.

Commission staff audited the company's books and reviewed internal work papers, invoices and contracts. Staff's audit recommended a $240,725 reduction to Rocky Mountain's total ECAM recovery request of about $23.3 million. The $23.3 million is about $10.7 million more than that already collected in the ECAM account. About $12.7 million and $1 million of that will be collected from Monsanto and Agrium Inc.

The biggest drivers increasing Rocky Mountain Power's power supply costs were decreased revenue from the company's energy sales into the wholesale energy market and increased expense to fuel its coal plants. Sales from energy Rocky Mountain sold to other companies decreased 42 percent while, at the same time, prices for power purchased by the company from the market were 7 percent higher than the amount included in base rates.

Coal fuel expense increased by 16 percent, which appeared to be driven by higher coal mining costs combined with an increase in the price for the coal the company buys.

The Lake Side 2 combined cycle combustion turbine natural gas plant in Vineyard, Utah, began commercial operation in May 2014 and is included as part of the ECAM until the company files its next rate case. At that time the commission will determine if the new plant is to be included in permanent base rates.

To encourage the company to be prudent in its power supply expenditures, the commission requires that shareholders pay 10 percent of ECAM expense.

Commission finds Rocky Mountain Power investment in demand-side management program is prudently incurred

Case No. PAC-E-14-07, Order No. 33188

Dec. 19, 2014 – About $25.76 million of Rocky Mountain Power company investment in demand-side management (DSM) programs during 2010-13 was prudently incurred and beneficial to both the company and its southeast Idaho customers, state regulators determined. The commission's finding does not impact customer rates.

DSM refers to programs that encourage customers to use less energy or shift use away from peak hours, thus reducing demand on Rocky Mountain's generation system. Customers pay for most of the programs through a rider that appears on customer bills called "Customer Efficiency Services." The rider is currently set at 2.1% of a customer's monthly billed amount. Investment in an irrigation load control program (about $8.1 million of the total $25.76 million) has been shifted to recovery through base rates rather than through the rider.
The commission's prudency review is to determine if the funds invested in the programs are reasonable and beneficial to customers, including customers who do not directly participate in the programs.

The programs, directed toward residential, commercial, industrial and irrigation customers, saved the utility 11,963 megawatt hours in 2010; 8,688 MWh in 2011; 11,420 MWh in 2012 and 18,324 MWh during 2013. That reduced consumption lowers power supply expense for all customers and eliminates or delays the need to build new generating facilities.

Commission staff audited the company's internal controls and processes and interviewed DSM program managers. Staff said Rocky Mountain has "rigorous internal controls" to help ensure precise allocation of the costs and benefits within each DSM program. The staff noted that in 2012 and 2013 the company surpassed its Conservation Potential Assessment and that in all years except 2010 exceeded its energy savings goals as outlined in its long-range Integrated Resource Plan.

Rocky Mountain Power offers three programs to residential customers. "Home Energy Saver" provides products and services such as attic insulation and floor insulation, energy efficient windows, CFL lighting and other services. "Refrigerator Recycling" offers rebates for removal and recycling of inefficient refrigerators and freezers. "Low-Income Weatherization" provides energy efficiency services to residential customers meeting income guidelines. Three other programs targeted commercial, industrial and agricultural customers. "FinAnswer Express" helped commercial and industrial customers improve the efficiency of their lighting, HVAC, electric motors, building envelopes and other equipment. "Energy FinAnswer" was available to commercial and industrial customers in excess of 20,000 square-feet and included incentives for improvements to HVAC systems, motors, refrigeration, lighting and other equipment. "Agricultural Energy Services" was designed to improve overall efficiency of irrigation systems. *(In a separate case, these programs were consolidated into a single program to be marketed as "wattsmart Business." All three were merged effective Nov. 1, 2014, under one tariff called Non-Residential Energy Efficiency, Schedule 140.)*

Only two of the programs did not pass cost-effectiveness tests. The portion of the Agricultural Energy Services program that offered irrigation customers a nozzle exchange as well as measures to make pivot and linear equipment more efficient has been discontinued. The Low-Income Weatherization program, while not yet cost-effective, will be continued while the company works with the commission and southeast Idaho community action agencies to increase participation.

The commission staff found that many of Rocky Mountain's industrial and commercial customers are not aware of the energy efficiency programs available to them. The commission directed the company to work more closely with staff to develop a more structured advertising method targeting non-residential customers.

Commission approves accounting treatment related to closure of Utah's Deer Creek mine

Case No. PAC-E-14-10, Order No. 33304

June 2, 2015 – The Commission approved an application by Rocky Mountain Power to set aside expenses related to the utility's decision to close a Utah coal mine for possible later recovery from customers.

The Deer Creek Mine near Huntington, Utah, is operated by Energy West Mining Company, a wholly-owned subsidiary of PacifiCorp, which does business in eastern Idaho as Rocky Mountain. The utility is seeking authority from the six states where it has customers to 1) incur costs for closing the mine; 2) withdraw from a contract it has with the United Mine Workers of American Pension Trust, which will incur a withdrawal liability; 3) sell the assets it has in the mine and; 4) enter into an agreements with Kentucky-based Bowie Resource Partners to provide replacement coal for the Huntington and Hunter plants in Utah that had been previously provided coal from the Deer Creek mine. Bowie trucks in coal to the Huntington plant from its mines in Utah's Carbon and Sevier counties.

The Idaho commission is required by state statute to approve any sale or purchase of property owned or to be owned by a utility it regulates. The commission is to determine whether the transaction is in the public interest, that rates will not be impacted and that a potential buyer has the bona fide intent and financial ability to operate and maintain the property in the public service.

The commission said the proposed sale is in the public interest because it mitigates the company's potential exposure to increasing pension and medical obligations to the mine's 182 employees and that the resulting cost for supplying electric service will be less going forward than it would have been without the transaction.

However, the commission denied the company's request to recover carrying charges before the next rate case. The commission also did not approve the company earning a return on expenses related to the mine's closure. Instead, the commission agreed to grant the company an accounting order that will allow it to defer costs related to the transaction for review by the commission after the company files its next rate case. A return on deferral during recovery may also be argued in the next rate case.

Included in the deferred account can be Idaho's portion (about 6 percent) of any loss on the sale of assets, construction work in process, closure costs and costs related to a retirees' medical obligation settlement. The commission denied the company's request to include carrying charges or a return on those costs because the plant is no longer "used and useful" to customers. Rocky Mountain said not allowing carrying charges and a return penalizes the company for a decision that benefits customers and puts the company in a position of financing the benefits of the transaction for customers over time. That ratemaking treatment limits the company's ability to fully recover costs and could dissuade utilities from undertaking similar actions in the future, Rocky Mountain Power said.

The commission said it "was not persuaded by Rocky Mountain's assertion that approval of a carrying charge is necessary to incentivize well-reasoned and cost-effective business decisions ..." Utilities should not to be "incentivized to act rationally in order to limit their losses," the commission said. Further, the commission said, delaying recovery of deferred items until after a rate case is filed "will enable the commission to fulfill its statutory duty to scrutinize and evaluate the actual costs of the transaction prior to making its decision regarding a reasonable return for those costs."

The PacifiCorp Idaho Industrial Customers and Monsanto opposed the application, stating it is too early to determine actual costs related to the closure until after a rate case is filed.

The mine, purchased in 1977, produces an average 3.5 million tons of coal annually. The mine had been the primary source of coal for the Huntington Power Plant in east-central Utah, which annually consumes about 2.9 million tons. It also supplied some coal to the Hunter Power Plant. The mine's depreciable life runs through 2019.

The mine's employees were represented by the United Mine Workers of America. Rocky Mountain said Energy West's health care costs and contributions to the pension trust were sharply increasing. Under the most recent labor settlement, Energy West was responsible for almost 100 percent of the health care costs, with employees paying a minimal co-payment and no premium cost-sharing. The deficit between the market value of the pension trust's assets and the present value of the vested benefits is about $5.5 billion.

In addition to labor issues, the mine is producing lower quality coal as it ages, which, in turn, reduces the volume of coal produced. As Energy West sought to develop additional areas of the mine's reserves, it discovered significant volumes of high-ash, high-sulfur coal, meaning much of it had to be transferred to a preparation plant nearby to be blended with lower-ash coals to meet coal quality specifications. More coal is available on the market, making it less advantageous to own coal mining assets, Rocky Mountain claimed.

PUC accepts Rocky Mountain Power long-range plan to reduce reliance on coal-fired generation

Case No. PAC-E-15-04, Order No. 33396

October 19, 2015 – The Commission accepted a long-range planning document filed by Rocky Mountain Power that spells out how the electric utility intends to meet future load growth. Rocky Mountain Power serves customers in eastern Idaho and much of Utah and Wyoming.

Acceptance of the Integrated Resource Plan, required by the commission to be filed every two years, does not mean the commission endorses all components of the plan, but acknowledges the utility meets the requirements for a long-range plan. "It is the ongoing planning process that we acknowledge," the commission said. Rocky Mountain Power intends to meet most of its growth in energy demand through an expansion of energy efficiency programs and from short-term wholesale market purchases.

A 59 percent increase in projected energy efficiency savings from the 2013 plan is anticipated to meet 86 percent of the company's forecasted load growth over the next decade. Rocky Mountain is also projecting a reduction in the rate of load growth from what it anticipated in 2013 due to the continued phase-in of federal lighting standards and increased efficiencies in heating, cooling, water heating, use of appliances and industrial process end-uses. PacifiCorp's preferred portfolio of energy sources includes 816 megawatts from power purchase agreements with 36 wind and solar projects, all scheduled to come on line by the end of 2016. While offering "no commentary on the prudency" of the decision for increased reliance on solar resources, the commission suggested Rocky Mountain consider "conducting a reasonable evaluation," of the costs and benefits associated with the integrating additional solar resources into its system.

Commission staff said the company may want to include a solar integration study in its 2017 plan. Rocky Mountain said it will consider a study, but noted that solar energy will comprise only about 2 percent of its projected load by 2017, rather than the 6 percent claimed by commission staff. The commission commended the company for responding positively to the commission's recommendation in 2013 that the utility expand its energy efficiency programs in response to anticipated increased federal regulation on fossil-fueled generation. This year's IRP is greatly impacted by the Environmental Protection Agency's recently announced Clean Power Plan.

Rocky Mountain plans to convert some coal generation to natural gas by 2018 and install emissions control equipment at its Wyodak and Dave Johnston Unit 3 coal projects in Wyoming and its Cholla Unit 4 project in Arizona. The plan states that about 2,800 MW of existing coal generation will either be retired or converted to natural gas-fired generation over the next decade.

While commending the company for its plan to phase out 2,800 MW of coal generation, the Snake River Alliance said the plan does not go far enough. The environmental organization said the company will still be relying on coal for as much as 30 percent of its generation two decades from now, which exposes customers to undue risk from increased regulation on coal-fired generation.

The Idaho Conservation League believes the company's modeling of future costs related to coal pollution costs is "fundamentally flawed."

In addition to increased reliance on energy efficiency programs, Rocky Mountain is also planning on transmission expansion. The utility plans to have access to more generation, much of it from wind, from three 500-kV transmission projects: Energy Gateway West (from Casper, Wyo. to the Hemingway Substation southwest of Boise), Energy Gateway South (from south-central Wyoming, through southeastern Idaho to central Utah) and Boardman to Hemingway (from Boardman, Oregon to the Hemingway Substation).