

ELECTRICAL POWER IN IDAHO



Idaho Power Company

2015 Average Number of Customers/Avg. Revenue/kwh*

418,906 Residential Customers/\$0.1030

80,261 Commercial Customers/\$0.0767

113 Industrial Customers/\$0.0567



Avista Utilities

2015 Average Number of Customers/Avg. Revenue/kwh*

110,267 Residential Customers/\$0.0949

17,267 Commercial Customers/\$0.0890

449 Industrial Customers/\$0.0590



Rocky Mountain Power

2015 Average Number of Customers/Avg. Revenue/kwh*

60,959 Residential Customers/\$0.1112

8,425 Commercial Customers/\$0.0895


5,544 Industrial Customers/\$0.0733

*Computed from data available in FERC Form 1 Annual Reports dated June 30, 2016.

ELECTRIC RATE CHANGES



PUC adopts settlement to Avista case

Case No. AVU-E-15-05, AVU-G-15-01, Order No. 33437 

Dec. 22, 2015 – The commission adopted a settlement to the Avista Utilities electric and natural gas rate case that increased electric rates an average 0.6% (six-tenths of 1%) and natural gas rates by 3.5% effective Jan. 1, 2016. The settlement is a significant reduction from Avista’s original electric rate request of 10.3% over two years – 5.2% in 2015 and 5.1% in 2017. On the gas side, Avista originally requested 4.5% in 2016 and 2.2% in 2017. The settlement reduces Avista’s requested annual electric revenue increase from \$13.2 million to \$1.7 million. It reduces the requested natural gas annual revenue increase from \$3.2 million to \$2.5 million. Avista sought a 9.9% return on equity and was granted 9.5%.

For a residential customer who uses the company average of 929 kilowatt-hours per month, the increase is about 75 cents per month. The original request would have increased bills by about \$5.92 per month in 2016 and \$6.10 in 2017. For a natural gas customer who uses the company average of 61 therms per month, the increase is about \$3.20 per month, counting the \$1 per month increase in the basic service charge. The original request would have increased natural gas bills \$3.90 per month in 2016 and \$1.79 per month in 2017. 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.

The commission approved the company’s request for an annual rate adjustment called the Fixed Cost Adjustment (FCA). The FCA will be a surcharge or a rebate granted every year depending on whether Avista recovers its fixed costs of doing business. During some years, the utility may not recover its fixed costs due to changes in conservation, weather or the economy. By ensuring that Avista recovers its fixed costs when electricity and natural gas sales decline, the FCA removes the disincentive for Avista to invest in and promote energy efficiency programs.

The FCA will have an initial term of three years and will be reviewed to determine whether the adjustment should continue. During those years when there is a surcharge, the charge cannot exceed 3%. There is no cap on the amount a rebate can be.

PUC adopts settlement to Rocky Mountain case

Case No. PAC-E-15-09, Order No. 33440

Dec. 23, 2015 – The commission adopted a settlement to various issues surrounding Rocky Mountain Power Company’s request to transfer some of its variable power supply expense into permanent base rates.

The settlement increases base rates about 3.9% in 2016 (2.8% for residential customers), but customers will notice a reduction of near the same size when the company files its annual Energy Cost Adjustment Mechanism (ECAM) to be effective in 2017. A residential customer who uses the average 801 kilowatt-hours per month would pay about \$2.35 more each month.

The settlement replaces a base rate case that Rocky Mountain Power would have filed during 2016. It also includes a “stay-out” provision that prevents another base rate increase until Jan 1, 2018 at the earliest. Rocky Mountain serves about 75,000 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 shifts \$10.2 million of expense currently collected through the ECAM into base rates. Customers will be credited about that same amount when the company files its ECAM in 2017. Commission staff estimated that the combined net impact of the base rate increase in 2016 and the projected ECAM decrease in 2017 will be about \$889,000 per year or 0.34% more than what customers would have paid through current base rates and the current ECAM.

About \$6.5 million of the \$10.2 million shift is expense related to revenue the company no longer receives from the trading of Renewable Energy Certificates (RECs). 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.

The commission said the settlement represents a “reasonable compromise” of various positions raised by the parties, which included the company, commission staff, the PacifiCorp Idaho Industrial Customers and Monsanto Company.

“The hallmark of reasonable compromise is a mutually beneficial resolution for both sides of a transaction,” the commission said. “Accordingly, the commission finds that the stipulation offers substantive benefits to both ratepayers and company.”

The Snake River Alliance, while not a party to the case, submitted written comments in support of the settlement.



Rocky Mountain ECAM is slight decrease while efficiency surcharge is slight increase

Case No. PAC-E-16-05, Order No. 33492

Case No. PAC-E-16-02, Order No. 33491



April 1, 2016 – The commission approved two rate adjustments – on an increase and the other a decrease – for Rocky Mountain Power customers that become effective April 1, 2016. Rocky Mountain Power’s annual Energy Cost Adjustment Mechanism (ECAM) will be a slight decrease to customers of 0.7 percent, or about 58 cents less on an average residential monthly bill. Its Customer Efficiency Services Rate is a 0.6 percent increase, from the current 2.1 percent of the monthly billed amount to 2.7 percent. For a residential customer who uses the company average of 837 kilowatt-hours per month, the increase will be 61 cents per month. Rocky Mountain Power serves about 73,000 customers in eastern Idaho.

Energy Cost Adjustment Mechanism

Rates for Rocky Mountain customers are adjusted either up or down every April 1 to account for power supply expense that varies from year to year depending on the previous year’s natural gas and coal, surplus power sales, power purchases and the market price of power. If variable costs are higher than what is already included in base rates, customers get a one-year surcharge; if they are lower, customers get a one-year credit. For the 12-month period ending Nov. 30, 2015, Rocky Mountain’s net power supply costs were \$9.3 million less than that included in base rates, resulting in a rate credit to customers.

Customer Energy Efficiency Services

Rocky Mountain invests in a number of programs that either shift consumption to off-peak hours (demand response) or reduce consumption (energy efficiency). Funding for those programs is collected from the Energy Efficiency Services line item on customer bills.

Expenditures for the programs increased by about 38 percent from \$3.2 million in 2014 to \$4.4 million in 2015 due to increased customer participation. Savings from energy efficiency programs increased from 11,410 megawatt-hours in 2014 to about 15,440 MWh in 2016.

The commission said it aware of the impact that any rate increase can have on customers, particularly those on low- and fixed-incomes. But, the commission also noted that effective demand-side management programs delay the need for the company to build or buy from higher-cost generation resources.



Idaho Power's annual adjustment mechanisms result in average 3.5% increase for customers

Case No. IPC-E-16-08, Order No. 33526

Case No. IPC-E-16-02, Order No. 33527



May 31, 2016 – Rates for most Idaho Power Company customers will increase by about 3.5 percent June 1. Rates go up or down every June 1 as part of the company's annual Power Cost Adjustment (PCA) and Fixed Cost Adjustment (FCA).

Power Cost Adjustment

Since 1993, the PCA allows Idaho Power to adjust rates up or down to reflect the company's "power supply costs" that change from year to year. Idaho Power gets about half its generation from hydroelectric facilities, so a large portion of its costs to provide electricity to its customers is dependent on Snake River streamflows. Other costs that vary each year are the market price of wholesale electric power, fuel costs, transmission costs for purchased power and the revenue it earns from selling surplus power.

Idaho Power reported and commission staff verified that power supply expense for the company is \$17.3 million less than what is included in the current PCA surcharge of 0.5405 cents per kilowatt-hour. The commission approved an increase in the surcharge to 0.6187 cents per kWh, which will increase an average residential bill by about 1.35 percent or \$1.32 per month. The PCA increase is 1.35 percent for residential customers and an average 1.57 percent increase for all customer classes. To offset that increase, the commission approved \$3.16 million in revenue sharing with Idaho Power customers and a \$4 million credit given customers from unused demand-side management (DSM) rider revenue.

Idaho Power shares its revenue with customers when its Return on Equity is greater than 10 percent. The utility's 2015 year-end ROE was 10.13 percent, which means the company will share \$3.16 million with customers. However, Idaho Power's earnings are down slightly from the 11.19 percent ROE during 2014, so the proposed \$3.16 million revenue sharing with customers is about \$5 million less than the revenue sharing customers received in last year's PCA. The commission said it is sensitive to economic conditions affecting ratepayers but has a "responsibility to balance the ratepayers' desire for affordable energy prices with the company's right to recover its costs and earn a reasonable return on its investments." The commission emphasized that money collected through the PCA can be used only for recovery of actual power supply costs and cannot be used to increase earnings or salaries. Power supply expense is tracked in a deferred account, audited annually by the commission.

Idaho Power attributes the higher PCA to 1) increased PURPA generation, 2) less revenue sharing with customers due to a lower Return on Equity in 2015; 3) lower than projected hydro generation; and 4) lower than forecasted wholesale market prices for electricity, resulting in lower sales volumes for Idaho Power when it sells its surplus power into the market.

The utility has about \$10 million additional expense related to power purchase contracts with solar developers. The solar contracts fall under the provisions of the Public Utility Regulatory Policies Act (PURPA), which requires utilities to purchase generation from qualifying renewable energy projects. The company said about 320 megawatts of PURPA solar projects and 50 MW of PURPA wind projects are expected to come online during the 2016-17 PCA year.

Reservoir levels in the region are lower than the 2015 forecast. While Idaho Power had a better water year in some parts of its service territory, last year's dry winter left reservoirs in the Upper Snake River Basin very low by summer's end. Actual hydro generation was 27 percent less than the company forecast.

Wholesale electric market prices declined due primarily to lower natural gas prices. Lower market prices reduced surplus sales volumes by 26 percent. Also, because wholesale market prices were lower, the company's market purchase volumes were 92 percent higher than forecasted.

Fixed Cost Adjustment

The FCA, implemented in 2007, is designed to ensure Idaho Power recovers its fixed costs of delivering energy when energy sales decline due to reduced consumption. Before the FCA, Idaho Power had no incentive to invest in energy efficiency programs because it lost revenue as customer consumption declined. To remove that disincentive, the Fixed Cost Adjustment was created to allow the utility to recoup its fixed costs of doing business. Even though consumption may decline, the fixed cost to serve customers does not.

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 2015, Idaho Power under-collected fixed costs of serving residential and small business customers by \$28 million, or \$11.17 million more than the amount already included in the FCA account. To recover those fixed costs, the commission approved an FCA increase of 2.2 percent, which will increase an average residential and bill would by about \$2.16 per month. The new FCA rate is 0.5416 cents per kWh. The FCA applies only to residential and small business customers.

During 2015, Idaho Power achieved a 22 percent increase in energy savings compared to 2014. In a separate case filed before the commission every year, Idaho Power must demonstrate that the programs that create energy efficiency savings must result in lower overall rates to customers than if the programs were not in place. Several studies have shown that energy efficiency and demand reduction are the least expensive source of energy for utilities. The FCA makes it possible for the company to aggressively pursue energy efficiency and demand-side management programs without fear of losing fixed costs to serve customers.

The 2015 PCA was a 1.1 percent decrease and last year's FCA was a 0.35 percent increase, resulting in an overall net decrease to customers.

PCA is up for Avista, but higher BPA credit results in 0.3% decrease for most customers

Case No. AVU-E-16-05, Order No. 33605

Oct. 4, 2016 – Two rate adjustments that became effective Oct. 1 for customers of Avista Utilities will result in an overall rate reduction of about 0.3 percent for residential and small-farm customers.

Customers will be given a \$516,000 rebate as part of Avista’s annual Power Cost Adjustment (PCA), but that rebate is not as large as last year, so the result is a slight increase in the PCA of about 0.2 percent as approved by the Idaho Public Utilities Commission. However, at the same time, a rebate given residential and small-farm customers from the Bonneville Power Administration’s Residential Exchange Program is increasing slightly. The net result of both the PCA and BPA’s credit is a decrease of 0.3 percent or about 30 cents per month on an average residential monthly bill.

Every year on October 1, the variable portion of Avista rates is adjusted up or down depending on the previous year’s power supply expense, which is largely determined by changes in hydroelectric generation and market prices for natural gas and electricity.

Lower natural gas prices and less operating expense at the Colstrip and Kettle Falls plants kept power supply costs down for Avista. But hydro generation that was 13 percent below normal, more expense related to the operation of the Palouse Wind plant and a change in the contract between Avista and Clearwater Paper resulted in overall greater PCA expense. Thus, the size of the PCA rebate to customers is reduced from 0.032 cents per kilowatt-hour to 0.017 cents per kWh.

Offsetting the PCA increase is a larger credit than currently given residential and small-farm customers as a result of the BPA Residential Exchange Program. BPA credits residential and small-farm customers of utilities who live near BPA’s hydroelectric projects along the Columbia River. The credit fluctuates each year depending on a formula BPA uses to calculate the benefit. A higher benefit this year results in an overall decrease to residential and small-farm customers of 0.5 percent.

Parties to Avista rate case propose settlement that reduces average hike from 6.3% to 2.6%

Case No. AVU-E-16-03, Order No. 33641

Nov. 15, 2016 – At the end of the year, the commission was considering a proposed settlement to the Avista Utilities rate case filed in June. The proposed settlement reduces the increase from an average 6.3 percent to 2.6 percent.

Parties to the case including commission staff, the Clearwater Paper Corporation, Idaho Forest Products, the Snake River Alliance and the Community Action Partnership Association of Idaho signed a negotiated settlement that, if approved by the commission, would reduce the size of Avista's requested annual revenue requirement increase from \$15.4 million to \$6.25 million.

The proposed settlement reduces the company's requested annual revenue increase by \$9.2 million.

Some of the most significant adjustments were a \$4.5 million reduction by moving Palouse Wind project net expenses from base rates to the annual Power Cost Adjustment process, a \$2.47 million reduction in Cost of Capital; \$1.33 million removed from revised net rate base; \$1 million removed from 2015 storm costs; \$333,000 reduced in administrative and general expense, board of director expense and other items; a \$310,000 reduction in non-union labor expense; and a \$171,000 reduction by removing all company officer incentives.

The proposed settlement reduces Avista's requested Return on Equity from 9.9 percent to 9.5 percent and its proposed Rate of Return from 7.78 percent to 7.58 percent. It also reduces the size of the increase in the Residential Basic Charge from the company's requested \$6.25 per month to \$5.75 per month. The current charge is \$5.25 per month.

The parties also agreed to meet before the next rate case to assess Avista's Low-Income Weatherization and Low-Income Energy Conservation education programs for possible improvements.

Avista serves about 125,000 customers in north-central and northern Idaho.

ENERGY EFFICIENCY FILINGS

Idaho commission begins prudence review of Avista Utilities' electric conservation programs

Case No. AVU-E-16-06, Order No. 33617

October 11, 2016 – Avista Utilities is seeking a determination from the Idaho Public Utilities Commission that nearly \$10 million it spent during 2014 and 2015 on electric efficiency programs was prudently incurred. *(A final order in this case had not been issued by the time this report was published.)*

The electric efficiency programs are expected to be cost-effective in order to be funded by the Energy Efficiency Rider paid by Avista's customers. Residential customers pay 0.245 cents per kilowatt-hour for the programs. The prudence review will 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 are screened by at least three cost efficiency tests to demonstrate that the savings realized are greater than the programs' costs.

Avista claims its energy efficiency savings for 2014 of 16,292 megawatt-hours exceeded its target of 15,330 MWh. Its 2015 savings of 14,789 MWh fell short of its target of 15,666 MWhs, but for the two-year period, its total savings of 31,081 MWhs met the target of 30,996 MWhs.

Avista hired an independent contractor, Nexant, to evaluate the cost-effectiveness of its efficiency programs. According to Nexant, the total benefit to all customers in 2014 was \$6 million and \$2.4 million in 2015. To be cost-effective, the programs must benefit not only those who participate, but all customers because the energy saved is less costly than if Avista were to generate an equal amount of energy itself or buy it from other sources. The programs may also delay the company's need to build or buy new generation.

Most of Avista's residential programs included rebates to customers who installed low-cost lighting and water-saving measures and weatherization materials and participated in appliance recycling programs. More than \$575,000 in rebates were provided to Idaho residential customers, according to Avista.

Avista reports that the revenue raised by the rider did not cover all program expenses. As of Dec. 31, 2015, the tariff rider balance is \$431,784 underfunded.

Commission OKs Idaho Power efficiency programs but asks company to review 4 percent rider

Case No. IPC-E-16-03, Order No. 33583

Sept. 19, 2016 – State regulators have approved the \$35.2 million spent by Idaho Power Company on energy efficiency and demand-response programs during 2015 as prudently incurred.

The purpose of the commission's annual review is to ensure the programs are cost-effective, meaning customers would be paying more for energy without the programs in place. The commission is asking Idaho Power to submit a proposal by year's end that could revise downward the 4 percent Energy Efficiency Rider currently assessed customers to pay for a number of the efficiency programs. According to a commission staff analysis, Idaho Power has collected, on average, about \$13.5 million more each year than it spends on efficiency programs. The proposal will help determine how the surplus funds should be used.

The commission is also asking Idaho Power to work with commission staff and Idaho Power's Energy Efficiency Advisory Group to consider offering more programs for residential and small-business customers and look at what is being offered by utilities in neighboring states.

Idaho Power offers 19 efficiency programs funded by the 4 percent Energy Efficiency Rider. It also offers three demand-response programs that are included in the annual Power Cost Adjustment (PCA), which is part of the Annual Adjustment Mechanism listed on customer bills.

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. The company claims these programs increased annual energy savings by 18 percent.

About \$28.5 million of the total \$35.2 million investment during 2015 was related to energy efficiency. The remaining \$6.7 million was spent on demand-reduction and included incentive payments to customer who volunteered to shift their consumption to non-peak times of the day.

Energy efficiency programs resulted in 162,533 megawatt-hours of savings, which includes 21,900 MWh from Idaho Power's participation in market transformation initiatives offered through the Northwest Energy Efficiency Alliance. Some of Idaho Power's energy efficiency programs include offering customer rebates for increased use of heating and cooling efficiencies and energy efficient lighting and appliances as well as creating efficiencies in commercial and industrial buildings. The largest amount of energy efficiency savings came from the commercial/industrial sector (102,074 MWh), followed by the residential sector (24,532 MWh), followed by the irrigation sector (14,027 MWh).

Demand reduction programs that provided financial incentives to residential air conditioning customers, large commercial and industrial customers and irrigators to shift or curtail consumption to off-peak periods reduced demand on Idaho Power's system by 376 megawatts, saving customers about \$1.6 million.

Rocky Mountain seeks prudence finding for investment in efficiency programs

Case No. PAC-E-16-14, Order No. 33639

November 4, 2016 – Rocky Mountain Power is asking the Idaho Public Utilities Commission to determine that about \$7.46 million of the company’s investments in energy efficiency programs during 2014-15 were prudently incurred and benefitted customers. This application does not impact rates. *(A final decision had not been made when this report was published).*

The programs encourage customers to use less energy or shift consumption to off-peak hours.

The programs are funded by a rider that appears as “Customer Efficiency Services” on bills. The rider is currently set at 2.7% of a customer’s monthly billed amount. Part of the commission’s prudence review is to determine if the programs benefit all customers, not just those who directly participate in the programs.

Rocky Mountain Power claims the programs saved the utility 11,410 megawatt hours in 2014 and 15,692 MWh in 2015. That decreased consumption reduces power supply expense for all customers and eliminates or delays the need for the company to build new generating facilities.

Rocky Mountain Power offers five energy efficiency programs.

- “Home Energy Saver” provides products and services to residential customers such as insulation, duct sealing, CFL and LED lighting and other services.
- “Refrigerator Recycling” offers customers rebates for removal and recycling of inefficient refrigerators and freezers.
- “Low Income Weatherization” provides energy efficiency services to residential customers meeting income guidelines.
- “Low Income Conservation Education” targets customers receiving low-income energy assistance and provides them information about how to better conserve energy and understand their bill.
- “Non-Residential Energy Efficiency” is a consolidation of commercial and industrial energy efficiency programs into a single portfolio the company calls “wattsmart.” It helps commercial and industrial customers improve efficiency in lighting, HVAC systems, motors, building envelopes and other equipment.

Rocky Mountain reports that, overall, the programs were cost-effective, meaning their benefits outweighed their cost. However, the low-income weatherization program, failed to pass two of three cost-effectiveness tests.

Rocky Mountain Power, a division of PacifiCorp, serves 75,500 customers in its eastern Idaho territory.

OTHER MAJOR ELECTRIC CASES

Idaho Power Company seeks 3.1 percent rate increase for accelerated Valmy closure and updated depreciation

Case No. IPC-E-16-23, Order No. 33652

Case No. IPC-E-16-24, Order No. 33650

November 18, 2016 – At year’s end, the commission had opened dockets to consider two Idaho Power Company requests: an accelerated depreciation for the Valmy coal plant in Nevada and an updated depreciation study for the remainder of the utility’s plant assets. A final decision had not been made when this report was published.

Idaho Power and Nevada Energy, co-owners of the Valmy plant, want to shut down the two-unit plant by 2025, six years earlier than the planned retirement of Unit 1 and 10 years earlier than the planned retirement of Unit 2. Consequently, Idaho Power is asking the commission to compress the remaining depreciation on the plants into the shorter 2025 time period, which, if approved, would increase base rates by \$28.5 million, or about 2.5 percent. The company maintains that an earlier retirement of the plant would save customers about \$103 million in today’s dollars if it continues to operate the plant until it is fully depreciated in 2035.

Idaho Power is also seeking a 0.6 percent increase to update the depreciation on its remaining plant assets, excluding Valmy and the Boardman, Oregon coal plant. The combined 3.1 percent increase, if granted, would increase the monthly bill of a residential user who uses the system average of 1,000 kilowatt-hours per month by about \$3.08.

If the commission were to approve both applications, the rate changes would not occur until June 1, 2017, the same time the annual Power Cost Adjustment (PCA) is also implemented.

Idaho Power is a 50-50 owner with Nevada Energy in the Valmy coal-fired plant near Winnemucca, Nev. The plant consists of two units that can generate up to 284 megawatts.

A significant decrease in market prices for electricity has made it uneconomical for Idaho Power to operate Valmy except to meet peak energy needs during extremely cold or hot weather. In 2011, the average price Idaho Power and its customers received for off-system sales was \$22.71 per megawatt. In 2016, that has declined to \$8.76 per MW. Consequently, the cost to dispatch Valmy generation is usually higher than the market price, Idaho Power claims.

Idaho Power further claims that since its last general rate case in 2011, Valmy plant balances have increased about \$70 million due to a number of investments required for environmental compliance, as well as investments for routine maintenance and repair.

In a separate application, Idaho Power is seeking a 0.6 percent increase, effective June 1, 2017, following an update of its depreciation on its remaining assets.

Utilities are allowed a depreciation component in retail rates to help cover the costs to replace facilities. Depreciation rates establish the amount of time over which Idaho Power recovers from customers its investment in its electrical system. Depreciation means the loss in the service value of a utility's various plants due to wear and tear or decay that is not otherwise restored by maintenance or covered by insurance. A loss in service value can also be caused by the obsolescence of plant due to new technologies and by new requirements imposed by federal or state governments.

Every five years, Idaho Power conducts a study to determine depreciation rates for each of its plant accounts. Idaho Power's depreciation study was conducted by Gannett Fleming Valuation and Rate Consultants, LLC.

Commission accepts Idaho Power long-range plan

Case No. IPC-E-15-19, Order No. 33441

Dec. 29, 2015 – The commission accepted a 20-year planning document filed by Idaho Power Company, although there is some disagreement from commission staff and other parties over whether the utility has chosen the most cost-effective, least-risk plan to meet load growth.

However, the commission noted that the Integrated Resource Plan (IRP) is for planning purposes only and that acceptance of the plan does not mean all its components will be implemented. The IRP is a "working document that incorporates many assumptions and projections at a specific point in time," the commission said. "It is a plan, not a blueprint, and by issuing this order we merely acknowledge the company's ongoing planning process, not the conclusions or results reached through that process." Regulated electric and gas utilities are required to file an IRP every two years with the commission.

The plan does not anticipate significant new generation resources through the 2020s. It projects customer growth to be about 196,000 from now until 2035, adding about 1.2% to the company's average energy demand and 1.5% to its peak demand.

To meet load growth, Idaho Power anticipates acquiring 60 megawatts from new demand response programs, 20 megawatts from development of an ice-based thermal energy storage plan, and the construction of a 300-MW natural gas plant in about 2031.

The plan also assumes that much of the increased demand in the near future will be met by completion of the 500-kilovolt Boardman (Oregon) to Hemingway transmission line, expected to be operational by 2020 or shortly thereafter.

Idaho Power is anticipating that Units 1 and 2 of the North Valmy, Nevada, coal plant it co-owns with Nevada Energy will be retired by 2025. Commission staff and other intervenors to the case said the company's preferred portfolio is more costly and risky than portfolios that would close the North Valmy Unit 1 six years earlier in

2019. But Idaho Power claims that early closure would immediately increase customer rates by \$6 million annually in depreciation expense. North Valmy Unit 1 isn't fully depreciated until 2031 and Unit 2 until 2034. Idaho Power gets about 260 MW from the North Valmy units.

Commission staff said Idaho Power's preferred portfolio was the sixth-most risky of 11 studied. Idaho Power said that while 2019 North Valmy retirement performed well in an economic analysis, early closure carries considerable risk due to a number of factors including the administration's Clean Power Plan and uncertainty surrounding PURPA solar projects, the completion date of the Boardman to Hemingway Transmission line, and whether regulators will allow depreciation expense of early coal plant retirement to be included in customer rates.

Since Idaho Power's IRP was filed last June, some of those risk factors have been lessened, commission staff said. Idaho's emission-reduction targets under the Clean Power Plan have been reduced and the compliance period extended. Furthermore, a recent commission order limits solar and wind PURPA contracts to two years. The commission encouraged the company "to more clearly explain" to stakeholders why the company chose a portfolio with a 2025 closure of North Valmy instead of 2019.

Staff and other stakeholders said Idaho Power's cost models that deduct achievable energy savings from the company's load forecast does not treat supply-side resources and demand-side resources equally. (Supply-side resources include traditional generation while demand-side resources include programs that reduce or shift demand from peak-use periods.) Idaho Power claims doing so would give demand-side resources preferential treatment.

In its order, the commission said Idaho Power should further explore whether it could more effectively incorporate energy efficiency by using cost models similar to those used by PacifiCorp, Avista Utilities, Puget Sound Energy and the Northwest Power and Conservation Council.

The Idaho Conservation League said Idaho Power overestimates solar costs and Clean Power Plan compliance costs while underestimating achievable energy efficiency.

The Snake River Alliance said Idaho Power should not rely too much on completion of the Boardman to Hemingway transmission line because of the project's history of delays. The utility should also take into account "social costs" related to carbon-based generation. It also said Idaho Power is not progressing rapidly enough in developing community solar projects.

The Sierra Club said Idaho Power should make an effort to more fairly estimate solar costs and should also consider transmission and distribution expense and not just generation expense in its financial analyses.

All of the intervening parties commended Idaho Power for inviting participation from various stakeholders in what they said was an improvement over past IRPs.

Update to Idaho Power green energy program approved

Case No. IPC-E-16-13, Order No. 33570

The commission approved Idaho Power Company's application to modify a program approved in 2001 that allows customers to participate in the purchase of green energy from primarily wind and solar resources in the Northwest.

Customers currently designate a dollar amount to be added to their monthly bills specifically to be used toward the purchase of Renewable Energy Certificates (RECs). A REC is created when one megawatt-hour of renewable energy is produced and delivered to the electrical grid. Purchase of the RECs means the utility uses less power generated from fossil fueled sources like coal or natural gas plants.

Idaho Power proposed to change the fixed dollar contribution to one of two other options for customers: buying blocks of power at \$1 for every 100 kilowatt-hour block of renewable energy or a "100 percent of usage option," which means the customer elects to buy renewable energy equal to the customer's total monthly use at a premium price of 1-cent per billed kWh.

Switching to these options, Idaho Power claims, will allow it to better comply with national green energy standards, create a more transparent program for participants and align Idaho Power's Green Power Program with similar programs offered in the Northwest.

As a second modification, Idaho Power proposed that the Bonneville Environmental Foundation (BEF), the Portland-based non-profit that secures REC sources for Idaho Power, give preference to RECs within or closest to Idaho Power's service territory when possible.

Thirdly, Idaho Power proposed that 15 percent of the program's funds be used for marketing to invite greater customer participation. Currently, about 1,700 customers participate as well as 15 schools, under the utility's Solar 4R Schools program. No program monies are currently used for marketing. If REC prices change significantly, Idaho Power may choose to use the marketing funds to cover the increase in REC prices rather than change the price to participants, but in no case, the company claims, will program funds be used for purposes other than the Green Power Program.

The company is considering, though not in this filing, later expanding the program to include a bulk-purchase option for large customers and adding a solar option, under which customers can direct that all the green energy they purchase come from solar sources. The market for solar RECs is not liquid enough at this time to include that option in this filing, Idaho Power said.

The commission approved the 15 percent dedicate for marketing the program, but did ask that the company file a Green Energy Prudency Report every two years to monitor marketing activities and expenses. The report will also include customer count, monthly RECs purchased, monthly revenue and expenses, Solar 4Schools expenses, percentage of RECs bought within Idaho Power's service territory and monthly funds transferred to the Power Cost Adjustment (PCA) from Idaho Power-owned REC purchases.

Integration costs to solar developers decline

Case No. IPC-E-16-11, Order No. 33563

August 12, 2016 – New solar developers will be paying significantly less to integrate their generation into Idaho Power Company’s transmission and distribution system under new integration rates approved by the Idaho Public Utilities Commission.

The solar integration charge paid by developers applies only to larger solar projects that enter into contracts with Idaho Power. It does not apply to smaller projects, such as residential and commercial rooftop solar.

Electric utilities incur costs based on the amount of solar generation added to their distribution and transmission system. Part of those integration costs are incurred when utilities need to provide back-up generation if solar output is less than anticipated.

In February 2015, the commission approved a settlement that adopted solar integration costs developers pay Idaho Power based on a 2014 study completed by the utility. However, the parties to that settlement did not agree on the tariffs recommended by the study. As part of the settlement, Idaho Power agreed to conduct a second study using a Technical Review Committee comprised of staff from the Idaho and Oregon public utility commissions, Idaho Power, and a technical expert designated by each of the parties to the settlement, which also included the Sierra Club, Idaho Conservation League and the Snake River Alliance.

The integration costs approved by the commission incorporate the results of the second study, which includes an updated tariff for each 100 MW of solar generation up to 1600 MW. (Idaho Power currently has 40 megawatts of solar generation online and another 290 MW under contract to be online by the end of this year.) At a total solar penetration of between 301 and 400 MW, the integration tariff to solar developers is 54 cents per megawatt-hour for a non-levelized contract signed this year. That compares to \$2.63 per MWh using the 2014 study. Between 401 and 500 MW of penetration, the new tariff is 71 cents per MWh compared to the 2014 tariff of \$3.31.

The Idaho Conservation League (ICL) and Renewable Northwest (RN) supported the changes Idaho Power made to its methodology to compute the tariff, but said the tariff should be based on an average rate rather than incremental approach that increases the rate for every 100 megawatts of solar generation added. That’s because future projects may have features that reduce integration costs, according to the ICL and RN. However, the commission declined to adopt that recommendation because averaging costs would “work to the detriment of early projects and to the benefit of later developers.” Integration costs to developers are determined at the time they sign the contract with Idaho Power and remain fixed for the duration of the contract. Subsequent changes to the tariff rate as solar integration increases would apply only to new contracts.

ICL and RN also requested that the methodology adopted by Idaho Power in its updated solar integration study be used to update the utility’s wind integration study. However, the commission said the “notable differences” between wind and solar generation make it impracticable to apply the solar study to wind integration.

The commission said the integration tariff should be updated frequently to account for changes that could be impacted by:

- The potential impact of Idaho Power joining the Western Energy Imbalance Market;
- Transmission changes, such as completion of the Boardman to Hemingway transmission line;
- Resource changes or additions, including generation received through customer participation in demand response programs;
- Energy storage;
- The combined effects of new solar and new wind;
- Changes in gas/fuel prices;
- The effects of distributed generation and community solar projects as they develop.

Idaho Power asks for declaratory order regarding solar project payments

Case No. IPC-E-16-21, Order No. 33619

October 7, 2016 – Idaho Power Company is asking state regulators to weigh in on a dispute between the utility and the developer of four 20-MW solar projects proposed to be built in southern Twin Falls County near the Nevada border. *(A final decision had not been issued when this report was published).*

The projects fall under the provisions of the Public Utility Regulatory Policies Act (PURPA), which requires utilities to buy from qualifying renewable generation at a negotiated rate that is to be based on the cost the utility avoids by not generating the power itself or buying it from another source.

Developers of generation projects can be paid two types of payments: energy payments and capacity payments. Energy payments are paid based on the energy produced at the time it is produced. Capacity payments are paid in addition to energy payments if the project's output is during a time when the utility is capacity deficient.

Idaho Power's latest filing with the commission regarding resource deficiency says the utility will be capacity deficient in 2024. The developer of the four proposed Jackpot Solar projects is seeking to enter into 10 successive two-year contracts, or 20 years of operation. The projects, if approved, would be eligible to start receiving capacity payments in 2024. Even if the resource deficient date were to change, projects with contracts signed this year would be eligible for capacity payments in 2024.

Jackpot Solar claims that the capacity price should be determined at the time of the initial two-year contract rather than at the beginning of the two-year term when the utility is capacity deficient. The developer claims that a 2015 Idaho Public Utilities Commission order that shortened contract lengths for these types of projects to two years, and a follow-up clarifying order, both determined that the deficiency date and the capacity rate are both calculated at the time of the initial contract.

Idaho Power is asking the commission to issue a declaratory order stating that the 2015 orders said just the opposite: that the capacity rate is determined at the beginning of each two-year term and that a PURPA project is not able to lock in an avoided-cost rate beyond the two-year maximum contract term. The four projects – Jackpot Solar North, Jackpot Solar South, Jackpot Solar West and Jackpot Solar East – are all 20 megawatts and all developed by Robert Paul.

Commission accepts Avista long-range plan

Case No. AVU-E-15-08, Order No. 33463

Feb. 11, 2016 – The commission accepted a long-range planning document that details how Avista Utilities plans to meet its projected load growth over the next 20 years.

The utility, which serves about 125,000 electric customers in northern Idaho, plans to acquire nearly all its energy from energy efficiency programs, natural gas plant upgrades and the construction of natural gas peaker plants and a combined-cycle natural gas plant.

Avista, like other electric utilities, must file the plan every two years. Acceptance of the plan does not necessarily mean the anticipated projects will be built. Instead, the report informs the commission and its customers about the utility's plans. The resource planning process can change as circumstances change.

While population and employment growth are starting to recover from the Great Recession, the utility nonetheless revised downward – from 1% to 0.6% -- its annual load growth projection from its 2013 IRP.

Efforts in energy efficiency have reduced Avista's load requirement by 127 average megawatts, about 11% of the utility's total load. Energy efficiency and market purchases push out the first anticipated long-term capacity deficit to 2021 at the earliest.

The first anticipated resource addition is a 96-megawatt natural gas-fired peaking plant at the end of 2020 to replace expiring contracts and serve load growth. In 2026, the company anticipates building a 286-MW combined-cycle combustion turbine natural gas plant, another 96-MW peaker plant in 2027 and a 47-MW peaker plant in about 2034. (Smaller peaker plants are built primarily to meet customer demand during peak-use periods while larger combined-cycle plants run year-round to meet load requirements.)

In total, the utility plans on adding about 565 MW of new natural gas generation through 2035 and acquiring another 132 average megawatts through energy efficiency programs.

Most of Avista's generation (51% in the winter and 38% annual average) comes from hydroelectric resources. Natural gas provides about 37% in the winter and 42% of annual generation. Avista also owns a 15% share in each of two Colstrip coal plant units in Montana, from where it gets about 222 MW. Coal comprises about 13% of Avista's annual generation.

The Snake River Alliance favored acceptance of the plan, but criticized what it believes to be Avista's over reliance on natural gas plants that, it says, are subject to unknown regulations and costs. Further, Snake River Alliance said, Avista's intent to acquire 565 MW of new natural gas resources while simultaneously shutting down demand response programs sends mixed signals about the utility's ability to achieve deeper carbon emissions reductions.

Demand response programs target typically larger-use customers who voluntarily agree to reduce or shift their consumption from peak-use periods in exchange for financial credits, thus reducing demand on Avista's overall generation system. Avista claims its demand-response programs have higher costs than anticipated and are not

cost-effective. Costs of the demand response programs would have to drop by nearly 50 percent to be cost-effective, Avista claims.

Commission removes net metering cap, directs Rocky Mountain to file annual report

PAC-E-16-07, Order No. 33511

May 4, 2016 – The commission denied a request by Rocky Mountain Power to increase a cap on net metering generation in its Idaho territory from 714 kilowatts to 2,000 kW. Instead, the commission removed the cap entirely and required an annual report that monitors the growth and impacts of net metering.

Net metering customers generate their own power to offset part or all of their energy use. Excess generation from net metering customers is fed back into the grid. The number of net metering customers in Rocky Mountain's Idaho territory has increased from just 2 in 2007 to 161 at the end of 2015, pushing net metering generation to about 1,049 kW. Nearly all of Rocky Mountain's net metering customers use residential and commercial rooftop solar applications.

The utility, which operates in eastern Idaho, has expressed concern that customers who do not net-meter may be subsidizing those who do. That's because a net metering customer who generates more than he or she consumes is paying little or no transmission or distribution costs to the company, even though the net metering customer is still on the grid. There is not enough net metering generation yet to make that subsidy significant, but the company believes the issue will need to be addressed as the amount of distributed generation increases. When net metering customers generate more than they consume, the utility credits the customer in future bills for the net amount of energy delivered back to the company. The credit is in the form of energy, not monetary payments.

The commission directed the company to file status reports with the commission on or about Oct. 31 of each year or when the company seeks to modify its net metering tariff. "We also expect the company to promptly notify us whenever changes to the net metering service materially affect the company's system and/or its other customers," the commission said.

The annual report should include customer participation levels, types of net metering generation, nameplate capacity, impacts on non-net metering customers and potential impacts to reliability, the commission said.

In response to a commission order when the net metering program was established, Rocky Mountain Power completed an analysis showing the difference between the value of the energy credited to net metering customers and energy market wholesale prices. On average, the company claims, it paid 10.34 cents per kilowatt-hour to net metering customers compared to a wholesale rate at the Mid-Columbia Trading Hub of 2.47

cents per kWh. The company claims that during 2015 it paid \$44,446 for excess net metering generation that had a corresponding energy wholesale market value of \$10,638.

In response to the company's claim, the commission adopted a recommendation by the Idaho Conservation League that Rocky Mountain include in its report a comparison of the value of excess net metering generation to the value of delivering alternative sources of power to end-users at the same time of day, month and year that the company is benefitting from net metering generation.

PUC accepts Rocky Mountain curtailment plan

Case No. PAC-E-15-10, Order No. 33519

May 4, 2016 – The commission approved an updated Rocky Mountain Power plan spelling out the steps the utility would take to curtail energy consumption during energy supply emergencies.

The plan, last updated in 1993, is outdated by advances in technology, changes in industry practice and the utility's generation capacity. Further, the 1993 plan addresses only long-term shortages and not the more typical short-term events. The updated plan addresses the more common short-term emergencies such as a temporary loss of generation, failed equipment, extreme weather and temperatures or a system disturbance within the Western Interconnection.

The commission said Rocky Mountain Power's plan contains "appropriate procedures" to temporarily interrupt electric service to customers during emergencies and power shortages while, at the same time, minimizing adverse impacts to customers and maintaining system reliability.

Rocky Mountain Power, a division of PacifiCorp, serves customers in Utah, southeastern Idaho and much of Wyoming.

The plan states that the company will endeavor to contact the commission before outages. "Such reporting is significant because the commission is the designated Energy Emergencies Coordinator for response and recovery efforts dealing with significant disruptions in energy supplies for all hazardous emergency situations," the commission said.

The plan recognizes that the utility already has demand-side management (DSM) programs under which customers reduce load during peak consumption during periods of short supply and it has large customers that already agree to be interrupted to achieve reductions in load.

The plan anticipates five stages that are used as the energy deficit increases.

The first stage is to implement load shedding from customers that can be contractually interrupted or are part of the company's existing DSM program. The second stage is a public appeal to voluntary load reduction by all customers. Third is a mandatory up to two-hour curtailment during peak hours by customers who have been grouped into blocks of about 100 megawatts near selected distribution feeders. However, distribution feeders serving facilities essential to the public welfare are avoided during this rotational curtailment. These include, among others, hospitals, 911 centers, airports, large water and sewer treatment plants, prisons, police and fire

stations and facilities critical to electric system operation. The commission said it expected Rocky Mountain “to take serious its commitment to identify and avoid curtailment of circuits that serve essential services.”

The fourth step is a mandatory curtailment in two-hour block rotations during peak or non-peak hours. The fifth and final step is mandatory emergency load reduction.

Under the former plan, only the State of Idaho could declare an energy emergency that would trigger curtailment. The updated plan recognizes the role of the Western Electricity Coordinating Council (WECC) and its Regional Reliability Coordinator to implement and enforce regional reliability standards in the western United States. Emergencies that threaten the integrity of the electric system can develop at any time due to a shortage of generation or disturbances on the system, either locally or within the Western Interconnection. Thus, the updated plan states that WECC or the Idaho Commission may order energy curtailments. However, nothing precludes Rocky Mountain Power from requesting voluntary load reduction at any time.

The plan eliminates financial penalties that could be assessed parties for noncompliance with curtailment orders.

“We encourage and look forward to more frequent updates by all utilities regarding their curtailment plans,” the commission said.

PacifiCorp updates net power costs; proposes plan that may keep rates stable through 2018

Case No. PAC-E-16-12, Order No. 33597

September 15, 2016 – PacifiCorp, which does business as Rocky Mountain Power in eastern Idaho, is asking the commission to update the base level of its net power costs to reflect reduced load and lower prices. The result would be a reduction in rates of about 0.4 percent effective Jan. 1, 2017. *(The commission had not yet issued a final order at the completion of this report.)*

In the alternative, the company is proposing a “Rate Mitigation Plan,” that would take this small reduction with a slightly larger reduction the company anticipates next fall and apply both against a future base rate increase. The plan, according to PacifiCorp, would keep rates stable through 2018 and mitigate the size of a future base rate increase. If the commission were to adopt the plan, the company says it would not file a general rate case before June 1, 2018 with new rates effective in early 2019 at the earliest.

Net power costs throughout PacifiCorp’s six-state territory were \$1.485 billion, less than the \$1.529 billion currently in base rates. Idaho’s portion of net power costs are \$91.6 million, down from \$94.8 million now in rates.

Rocky Mountain Power anticipates that its annual Energy Cost Adjustment Mechanism (ECAM) could be a \$4.5 million to \$5.5 million reduction next fall. The Rate Stability Plan would leave the ECAM at current levels and also apply the anticipated lower ECAM against the amount that would be sought in the company’s next rate case.

Net power costs are those costs the company pays to provide generation to customers, whether from its own generation plants, the wholesale market or power purchase contracts as well as related fuel, transportation and transmission costs. They do not include fixed costs like physical plant and operations and maintenance. Net power costs are always variable because of changing weather and market conditions.

The net power cost that is included in base rates is the basis from which the annual ECAM is calculated. If net power costs are greater than that included in base rates, customers get a one-year surcharge. If they are less, customers get a one-year credit.

Idaho commission approves two-year extension of cost-sharing arrangement among PacifiCorp states

Case No. PAC-E-15-16, Order No. 33623

October 18, 2016 – The commission approved a two-year extension of a plan that allocates PacifiCorp’s cost of serving its customers across its six-state territory based on each state’s share to PacifiCorp’s total system load. PacifiCorp does business in eastern Idaho, Utah and Wyoming as Rocky Mountain Power.

The “Multi-State Protocol,” increases the revenue requirement by 1.7%, or \$150,000 above the current Idaho share of \$986,000. The increase does not immediately impact rates, but allows PacifiCorp to set aside \$12,500 per month for possible recovery from customers in a rate adjustment that would be effective Jan 1, 2018 at the latest.

In 1989, Pacific Power and Light merged with Utah Power & Light to create PacifiCorp. After that merger, each of the six state commissions in PacifiCorp’s territory apportioned costs to customers using different methods. PacifiCorp claimed at the time that each state’s differing methods resulted in the utility not being able to fully recover its costs. That led to uncertainty in financial markets about whether PacifiCorp would be able to recover its investment in capital improvements and additions. A multi-state process was formed in about 2002 to allow the company and all six states to continue discussions about an equitable way to allocate costs so that customers pay for the benefits they receive, while not subsidizing customers in other states. The first protocol was adopted in 2005 and the second in 2010.

The 2010 protocol still did not collect enough to fully recover PacifiCorp’s cost, the utility claimed. To address the shortfall, PacifiCorp and the signers of the agreement agreed to a fixed-dollar “equalization adjustment” to be added to each state’s revenue requirement. The total for all states is an additional \$9.1 million, or about a two-tenths of 1 percent increase in each state’s annual revenue requirement.

The 2017 Protocol update was negotiated and agreed to by representatives of PacifiCorp, the staffs of the Idaho, Oregon, Utah and Wyoming commissions and other interested stakeholders. California did not participate in the discussions but implements the allocation methodology adopted by the other states. Washington participated in early discussions, but previously adopted a different allocation methodology.

The protocol does not make other changes to the 2010 agreement because of uncertainty over the impact of the federal government's proposed Clean Power Plan as well as the possibility that PacifiCorp may become part of a regional independent system operator.

The protocol continues the past "rolled-in method," that ensures each state pays only for PacifiCorp's prudently incurred costs to serve that state.

"We recognize that different rolled-in methods exist, and that some of them could have increased PacifiCorp Idaho's revenue requirement beyond the increase proposed here," the commission said.

The 1.7 percent increase to the Idaho revenue requirement "appropriately follows the principle that cost-causers should be the cost-payers and reasonable ensures Idaho customers will pay only for the share of total system costs that PacifiCorp prudently incurs to serve them," the commission said.