Electrical Power in Idaho

Idaho Power Company

2013 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
405,542 Residential Customers/$0.0957
78,334 Commercial Customers/$0.0718
111 Industrial Customers/$0.0515

Avista Utilities

2013 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
107,458 Residential Customers/$0.0884
16,830 Commercial Customers/$0.0842
454 Industrial Customers/$0.0531

2013 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)

PacifiCorp/Rocky Mountain Power

58,730 Residential Customers/$0.1103
8,360 Commercial Customers/$0.0906
5,571 Industrial Customers/$0.0699

Average Residential Retail Price of Electricity by State

The information below is provided by the Energy Information Administration of the U.S. Department of Energy (www.eia.gov) and reflects the average residential rate by kilowatt-hour by state in August 2014. Idaho ranks 44th of 50 states and the District of Columbia. The states with lower rates than Idaho from the lowest up are Washington, West Virginia, Louisiana, Arkansas, Kentucky, Oklahoma and Tennessee. States with the highest rates are Hawaii, Alaska, Connecticut, New York, Rhode Island, Vermont and Massachusetts.

State	August 2014 (cents/kWh)	August 2013(cents/ kWh)
Alabama	11.79	11.60
Alaska	20.43	18.71
Arkansas	10	9.97
Arizona	12.44	12.33
California	18.12	16.54
Colorado	12.83	12.57
Connecticut	19.67	17.57
D.C.	12.66	12.98
Delaware	14.12	12.67
Florida	11.98	11.32
Georgia	12.52	12.34
Hawaii	37.81	36.79
Iowa	13.42	12.40
Idaho	**10.54**	**10.27**
Illinois	11.95	10.31
Indiana	11.56	11.06
Kansas	12.74	12.06
Kentucky	10.08	9.87
Louisiana	9.77	9.72
Massachusetts	17.69	15.90
Maryland	13.71	13.89
Maine	15.35	14.37
Michigan	14.88	14.98
Minnesota	12.85	12.74
Missouri	12.71	12.30
Mississippi	11.62	10.81
Montana	10.89	10.93
North Carolina	11.44	11.33
North Dakota	10.94	10.87

State	August 2014 (cents/kWh)	August 2013(cents/kWh)
Nebraska	12.06	11.93
New Hampshire	17.18	15.93
New Jersey	16.0	16.23
New Mexico	13.57	12.64
Nevada	12.63	11.76
New York	19.49	19.15
Ohio	13.50	12.72
Oklahoma	10.13	9.91
Oregon	10.75	10.20
Pennsylvania	13.91	13.25
Rhode Island	18.38	15.73
South Carolina	12.48	12.01
South Dakota	11.42	11.35
Tennessee	10.47	10.24
Texas	12.01	11.47
Utah	11.56	11.23
Virginia	12.00	11.59
Vermont	17.87	17.08
Washington	8.93	8.93
Wisconsin	14.26	14.41
West Virginia	9.52	9.72
Wyoming	11.13	10.72

Recent History of Base Rate Electric Cases

IDAHO POWER

Year	Requested	Granted
2005	6.3%	6.3% *(Not a base rate case, but increase granted due to tax settlement and Bennett Mountain plant)*
2006	7.8%	3.2% *(net was **14% decrease** due to expiration of tax adjustment.)*
March 2008	10.35%	5.2%
June 2008	Though not a base rate case, rates increased an average 10.7% due to a one-year PCA surcharge and 1.37% added to base rates for Danskin plant.	
2009	10%	4% (tiered-rates implemented)
2010	No base rate case. Rates decreased an average 5.2%, due primarily to a Power Cost Adjustment decrease.	
June 2011	Three surcharge adjustments result in average 3% reduction for customers.	
2012	10%	4.2% (but net increase was 3.44% due to reduction in energy efficiency rider.)
2013	No base rate case. Annual Power Cost Adjustment was an average 15.3% increase effective June 1, the fourth-highest PCA on record.	
2014	No base rate case. The annual PCA is a 1% increase and FCA is a 1.2% increase.	

AVISTA UTILITIES

Year	Requested	Granted
2004	11%	1.9%
2008	16.5%	11.9% (Also, 4% PCA increase)

Year	Requested	Granted
2009	12.8% base rate increase with 5% PCA reduction, for net 7.8%	5.7% (but with 4.2% PCA reduction, net increase was 1.5 percent)
2010	14%	9.25% (but spread over 3 years)
2011	3.7%	1.1% (but with decreases in PCA and other rate components, the net is a decrease of 2.4 percent)
2013	4.6%	1.9% (with stay-out provision for next rate adjustment no sooner than Jan. 1, 2015.) On Oct. 1, 2013, Customers got a 1.3% decrease due to reduction in Energy Efficiency Rider.
2014	A rate settlement precludes any base rate increase until Jan. 1, 2016 at earliest.	

ROCKY MOUNTAIN POWER (PacifiCorp)

2005	5.1%	5.1% (This increase only applied to irrigation and industrial customers; no increase to residential.)
2007	10.3%	6.4%
2009	4%	3.1%
2011	13.7%	6.8% (but net increase to customers was 5.5% because of 1.3% reduction to Energy Efficiency Rider)
2013	--	A settlement prior to a formal case filed increased rates by an average 0.77% effective Jan. 1, 2014, with stay-out provision to Jan. 1. 2016.
2014	No base rate case. Annual Energy Cost Adjustment Mechanism (ECAM) is a 2.6% decrease	

Summary of major cases

Idaho Supreme Court upholds IPUC decisions in PURPA appeals, while IPUC and FERC settle

In late 2013, the Idaho Supreme Court and the Federal Energy Regulatory Commission affirmed the Idaho Commission's denial of a number of PURPA wind projects.

Since then, the Commission has significantly updated the process it uses to determine pricing and other terms for power purchase agreements between a utility and a PURPA developer.

Wind and solar projects (intermittent resources) must now negotiate with utilities using a commission-approved methodology with the utility's long-range planning document, called an Integrated Resource Plan (IRP), as a starting point. The IRP method more precisely values the energy being delivered. It does this by recognizing the individual generation characteristics of each project and assessing when the project is capable of delivering its resources against when the utility is most in need of the energy. The IRP methodology recognizes that larger projects have a greater effect on a utility's ability to balance its total load and resources.

Idaho Supreme Court building

THE ISSUE

In November 2010, Idaho Power Company, Avista Utilities and PacifiCorp asked the commission to investigate the rapidly expanding number of PURPA wind projects in Idaho. The utilities said the wind developers were "gaming" the system by disaggregating large projects into several smaller projects a mile apart, each with its one unique name created under a Limited Liability Corporation (but the same owner). FERC rules require a mile separation between Qualifying Facilities. The projects were disaggregated so that each one fell under the 10 aMW limit that qualified them for the commission's typically more attractive published rate.

THE PROBLEM

The utilities claimed the rapid development of these projects was having a profound price impact on customers and on the ability of utilities to integrate the wind

projects with their transmission systems. The utilities said the small-power projects PURPA was originally intended to encourage were instead being developed by sophisticated large-scale wind farms.
A problem for the Commission is that avoided cost rates – the cost the utility avoids by not having to generate the power itself or buy it from another source – had not been updated for new contracts. Fuel prices, which are a significant component in determining avoided cost, had dropped significantly in recent years. The avoided cost rate for new contracts did not go down as natural gas prices fell, making the commission's published rate considerably more attractive than wholesale market prices for power. This, along with a federal tax credit for wind development, contributed to a flurry of PURPA wind development.

ORDERS AND APPEALS

On Feb. 7, 2011, the Commission *temporarily* reduced the eligibility cap under which projects can qualify for published rates from 10 aMW to 100 kW, but only for intermittent wind and solar. The cap remained 10 aMW for other PURPA projects. The Commission said it would open a second phase of the original case to further investigate the disaggregation issues and determine whether the temporary changes in the eligibility cap should be made permanent.

On June 8, 2011, the Commission affirmed its decision to maintain the 100 kW eligibility cap for published rates for wind and solar projects, due to their intermittency and potential for continued disaggregation. Utilities were still subject to the "must-buy" provisions to purchase QF

power from wind and solar projects, but at a rate negotiated between the utility and the QF using a commission-approved Integrated Resource Plan (IRP) methodology. Seventeen wind projects did not meet the commission's criteria and were thus not eligible for published rates and would need to negotiate a rate with the utilities based on the IRP methodology if their projects were to go forward.

On Sept. 7, 2011, the Grouse Creek projects appealed to the state Supreme Court after being denied reconsideration by the commission. Concurrently, another set of projects, called the Cedar Creek projects, filed for a Petition for Enforcement at FERC, challenging the Commission's decision to lower the eligibility cap for wind and solar projects effective Dec. 14, 2010.

On October 4, 2011, FERC declined to pursue an enforcement action against the Idaho PUC regarding the Cedar Creek projects, but issued a Declaratory Order that said the PUC's decision not to approve the Cedar Creek projects was inconsistent with PURPA. The Cedar Creek and Grouse Creek projects were remanded to the PUC for further discussion.

On December 21, 2011, the PUC approved a settlement of the Cedar Creek projects. The settlement reduced the projects from five to three and moved them to a location better suited to transmission access. Settlement talks with Grouse Creek were not successful.

On March 2, 2012, Rainbow Ranch petitioned FERC to bring an enforcement action against the PUC for disapproving their projects. FERC declined, but issued a Declaratory Order stating the IPUC's decision to not approve the projects was inconsistent with PURPA.

On Sept. 7, 2012, the Commission affirmed its denial of Grouse Creek's two PPAs. The Commission clarified that despite FERC's statements to the contrary, the Commission has never made a determination that the creation of LEO occurs <u>only</u> when a QF and utility enter into a signed agreement. In this case, both parties entered into agreements that unequivocally state an effective date. Hence, the discussion of a LEO is moot. ***(LEO stands for "legally enforceable obligation," which signifies that an obligation exists for the utility to accept power produced by a qualifying independent power developer. The LEO provision is included in FERC regulations to prevent a utility from circumventing its obligation to purchase from Qualifying Facilities by refusing or delaying to enter into a contract with the QF. Federal PURPA law allows state commissions to determine when a LEO exists under state law, often on a case-by-case basis. A LEO may be incurred before a PURPA contract is reduced to writing.)***

On Sept. 25, 2012, the Murphy Flats projects asked FERC to take enforcement action. On Nov. 20, 2012, FERC declared it would bring an enforcement action.

On March 22, 2013, FERC filed a complaint in the United States Court for the District of Idaho asking the Court to enter an order finding that the Idaho Commission violated PURPA, enjoining the PUC from imposing conditions on the sales agreements between Idaho Power and developers of the Grouse Creek and Murphy Flats projects and directing the PUC to issue orders approving the agreements. This was the first time FERC had taken a state to court over a PURPA-related action.

On Dec. 18, 2013, the Idaho Supreme Court unanimously affirmed the PUC's decision to deny approval of the Grouse Creek contracts. The Court affirmed the PUC's requirement that a finding of a LEO requires a showing that there would have been a contract but for the actions of the utility. "Unlike a court of law, IPUC is a regulatory agency performing judicial and legislative functions. Therefore, it is not bound by its prior decisions. In addition, allowing Grouse Creek to sell power at the rates in place prior to the eligibility cap adjustment would not have been in the public interest," the court said.

Six days later, FERC and the IPUC signed a Memorandum of Agreement under which FERC will dismiss its court claims and the PUC dismiss any counterclaims. The Idaho PUC acknowledged that a LEO may be incurred prior to the signing of a contract. Both parties acknowledged that PURPA establishes a program of "cooperative federalism" under which FERC issues regulations to implement federal policy while state regulatory authorities are responsible for implementing those same regulations in a manner that accommodates local conditions and concerns so long as the implementation is consistent with PURPA.

PUC denies Idaho Power solar application, but says integration charge warranted

Case No. IPC-E-14-09, Order No. 33043

May 28, 2014 – The commission denied an Idaho Power Company request to temporarily suspend its obligation under federal law to sign new contracts to buy power from qualifying small solar-power producers.

However, the commission agreed with Idaho Power's contention that the utility incurs expense when it integrates solar generation into its system and that future contracts should include integration costs in the form of a discount to the amount the utility pays solar developers, ensuring that these costs are not passed on to customers.

Idaho Power's application did not affect net metering customers who have rooftop solar projects, but applied only to larger-sized (like 10- and 20-megawatt) solar projects seeking contracts under PURPA, the federal Public Utilities Regulatory Policies Act.

Idaho Power sought a temporary suspension from its PURPA obligation because it claimed that "dozens of solar projects" are either already under contract or attempting to obligate Idaho Power to buy up to 500 megawatts of electric capacity. The utility is expecting a mid-June completion of a study to determine its cost to integrate solar power. The company claims it is experiencing a rush of contract proposals from developers who know solar integration charges may be coming. If the commission did not grant the utility's request to suspend, it asked the commission to issue an order stating that all future solar PURPA contracts include an integration charge.

The commission said it appreciated Idaho Power's concern that the pending completion of its solar integration study has resulted in a "run-on-the-bank," but suspending Idaho Power's PURPA obligation "is not the appropriate remedy."

Instead, the commission said, Idaho Power and solar developers should include consideration of a solar integration charge when they negotiate their contracts. The parties might consider a "placeholder" integration charge and agree to implement the charge when the study is completed, the commission said. Another alternative may be to use the integration assessed wind developers – $6.50 per MWh – until a solar charge is approved.

The commission said the company offered no explanation as to why it did not begin the study sooner or completed it in a more timely manner. The commission said it agreed with several who testified at a public hearing last week that the "imminent crisis caused by the lack of a completed study is of the company's own making." The commission directed Idaho Power to complete the study "as soon as possible." The commission said Idaho Power's filing "reinforced our previous view" that integration charges should be part of power purchase contracts with small-power producers. "These charges may vary from very little to more, based on project location, project size and other factors," the commission said. The commission did not agree with those who say the benefits and value of solar are not considered when determining an integration charge. The value of solar is reflected in the rates that are paid developers, the commission said.

Solar development takes off; 120 MW approved during 2014, another 281 MW proposed

Case No. IPC-E-11-15, Order No. 32974
Case No. IPC-E-14-19, Order No. 33179;
Case No. IPC-E-14-20, Order No. 33180

In the first case listed above (IPC-E-11-15), the Commission found that there was no contract or LEO between Grand View Solar II and Idaho Power because Grand View had conditioned its offer to sell power on basis of receiving all the Renewable Energy Certificates (RECs).

In the subsequent case, approved in November 2014, parties agreed to split the RECs 50-50, as the PUC advocated in the initial case.

The Commission approved sales agreements between Idaho Power Company and the developers of two solar generation projects totaling 120 megawatts.

Grand View PV Solar Two LLC, 20 miles southwest of Mountain Home, is 80 MW and is scheduled to be online by Sept. 1, 2016. The project is expected to include about 340,480 polysilicon photovoltaic panels installed on a single-axis tracking system. The developer is Robert Paul of Boise.

Boise City Solar LLC is a 40-MW project to be built southeast of Kuna on Sand Creek Road with a proposed online date of Jan. 16, 2016.

The project is expected to use mono-crystalline solar modules and is a dual-axis tracking system, which allows the tracker to follow the sun both vertically and horizontally.

The developer is Mark van Gulik of Intermountain Energy Partners, headquartered in Ketchum with development offices in Boise. IEP will lease the land on which the project will be built from the City of Boise.
IEP will be paid by Idaho Power for the project's output, while the city will receive lease payments as well as half of the revenue received from the sale of Renewable Energy Certificates (green tags) associated with the project.

Idaho Power will also receive 50 percent of REC proceeds.

The commission received more than 140 written comments from the public, all encouraging their approval. "While many of the comments appeared to be based on a form-letter campaign, many others were original and thoughtful comments from citizens who appeared to be concerned about the environment and optimistic about the contribution" the projects would have on the economy. "We appreciate the public's participation in our process. "

The projects are the first of their type since the Idaho commission adopted an updated pricing method for intermittent projects (like solar and wind) that fall under the provisions of PURPA, or the federal Public Utility Regulatory Policies Act.

PURPA requires regulated utilities to buy energy from independent, renewable generation projects at rates established by state commissions. The rate to be paid small-power producers is called an "avoided-cost rate," because it is based on the incremental 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 customers because all amount utilities pay to qualifying small-power producers is included in customer rates.

The updated pricing method requires the developer and utility to negotiate a rate based on a methodology that uses the utility's long-range plan, called an Integrated Resource Plan (IRP), which considers, among other factors, the utility's need for the resource and the times when the energy is generated. "We intend that the IRP methodology be a flexible tool, taking into account many different variables, and producing a result that accurately values a project's capability to deliver resources in relation to the timing and magnitude of the utility's need for such resources," the commission said.

Under the agreements, Idaho Power pays the developers a non-levelized rate over the 20-year term, which means payments increase over the course of the agreement and vary according to light-load and heavy-load hours of the day and seasons of the year.

For Grand View, payments would vary from as low as $31 per megawatt-hour for light-load hours during the early months of the agreement to as high as $159 per MWh for heavy-load hours during the latter years of the agreement. If the payments were levelized over the 20-year term of the agreement, payments would be about $71.48 per MWh, after adjustments made by commission staff and Idaho Power. The estimated 20-year contractual obligation based on anticipated generation levels is about $300 million.

The agreement allows for a 5% deviation in monthly energy deliveries. If generation deviates by more than that, a price adjustment can be imposed against the developer, but the reduced payment to the developer can be no more than 10%. If there is a consistent and material deviation from the hourly energy estimates, the project will be considered to be in breach of the sales agreement.

The Grand View agreement also contains a solar integration charge which the developer pays Idaho Power to cover the cost of integrating the solar energy into Idaho Power's transmission and distribution system. The negotiated charge starts at 99 cents per MWh in the first year of the agreement and escalates to $1.84 per MWh in 2036.

The agreement with Boise City Solar LLC also includes non-levelized payments over 20 years. Payments would vary from as low as $44 per megawatt-hour for light-load hours during the early months of the agreement to as high as $113 per MWh for heavy-load hours during the latter years of the agreement. If the payments were levelized over the 20-year term of the agreement, they would be about $71.43 per

MWh, after staff and company adjustments. The 20-year contractual obligation based on estimated generation levels is about $160 million. The project is allowed a 2% deviation from its estimated monthly energy output before a price adjustment can be imposed, also capped at no more than 10%. And, as with Grand View Solar, material deviations from hourly energy estimates may be considered as a breach of contract.

The negotiated solar integration charge starts at $1.34 per MWh in the first year of the agreement and escalates to $3.11 per MWh in 2036.

Idaho Power submits sales applications for sales agreements with 11 solar projects

Nov. 14, 2014 – Idaho Power Company is proposing that the Commission was accept or reject power sales agreements between it and 11 solar projects totaling 281 megawatts. All told, the 11 projects have a 20-year estimated contract value of $973.5 million.

Six of the proposed projects, including the largest 71 MW facility, are planned for Elmore County. Three are in Power County, one in Ada County and one in Owyhee County. All have scheduled online dates in December 2016. See the attached table for a detailed listing of the projects, their size and contract value.

All the projects are qualifying facilities under the provisions of the federal Public Utility Regulatory Policies Act. PURPA requires regulated utilities to buy energy from independent, renewable generation projects at rates established by state commissions. The rate to be paid small-power producers 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 100 percent of the price utilities pay to qualifying small-power producers is included in customer rates.

Six of the projects are owned by Ketchum-based Intermountain Energy Partners. Mark van Gulik is the developer. Five of the projects are owned by First Wind, headquartered in Boston.

The sales agreements propose that Idaho Power pay the developers a non-levelized avoided-cost rate over the 20-year term of the agreements, which means payments increase over the course of the agreement and vary according to light-load and heavy-load hours of the day and seasons of the year.

The Intermountain Energy projects propose rates that are as low as $33 per megawatt-hour during light-load hours to as high as $115 per MWh during heavy-load hours. If the payments were levelized over the 20-year term of the proposed agreements, payments would be about $62 per MWh. The scheduled online date for those projects is Dec. 31, 2016.

The First Wind projects propose rates as low as $33 per MWh during light-load hours to about $143 per MWh during heavy-load hours. If levelized, the payments would be about $64 per MWh. The scheduled online date for the First Wind projects is Dec. 1, 2016.

Included in each contract is an integration charge the developer pays Idaho Power to cover the cost of integrating the energy into Idaho Power's transmission and distribution system.

Revenue from the sales of Renewable Energy Certificates associated with the projects would be split 50-50 between the developer and Idaho Power.

The proposed agreements allow for a 2 percent deviation in estimated energy output before the price can be adjusted. A consistent deviation from the hourly energy generation estimates would be considered a material breach of the agreements.

Project	Location	Size	20-year estimated contract value
Mountain Home Solar Case No. IPC-E-14-26	Elmore County	20 MW	$81 million
Pocatello Solar 1 Case No. IPC-E-14-27	Power County	20 MW	$75.6 million
Clark Solar 1 Case No. IPC-E-14-28	Elmore County	71 MW	$250.75 million
Clark Solar 2 Case No. IPC-E-14-29	Elmore County	20 MW	$69.85 million
Clark Solar 3 Case No. IPC-E-14-30	Elmore County	30 MW	$103.6 million
Clark Solar 4 Case No. IPC-E-14-31	Elmore County	20 MW	$68.15 million
Murphy Flat Power Case No. IPC-E-14-32	Owyhee County	20 MW	$68 million
Simco Solar Case No. IPC-E-14-33	Elmore County	20 MW	$68.7 million
American Falls Solar Case No. IPC-E-14-34	Power County	20 MW	$63.8 million
American Falls Solar II Case No. IPC-E-14-35	Power County	20 MW	$60.7 million
Orchard Ranch Solar Case No. IPC-E-14-36	Ada County	20 MW	$63.5 million

Parties negotiating solar integration charge

Case No. IPC-E-14-18, Order No. 33173

Nov. 6, 2014 – A technical hearing regarding Idaho Power Company's application to implement a solar integration charge that had been scheduled for Nov. 13, 2014, was vacated to allow an opportunity for parties to the case to enter into settlement negotiations.

Parties include Idaho Public Utilities Commission staff, the Idaho Conservation League, the Snake River Alliance and the Sierra Club.

The integration charge Idaho Power proposes would be assessed larger solar developers to compensate Idaho Power for costs it incurs to integrate solar output into its transmission and distribution system. This application does not impact residential or small-commercial customers who have rooftop solar installations.

Solar and wind generation is intermittent, meaning that that they vary in energy output depending on sun and wind conditions. That intermittency requires that Idaho Power have back-up generation to ensure system reliability. Utilities must provide operating reserves from baseload (non-intermittent) generation resources – such as a natural gas or hydro plant – that can be quickly ramped up or down to offset changes in generation from variable generation. Restricting the use of baseload resources to provide back-up for intermittent generation results in higher power supply costs that are eventually passed on to customers, Idaho Power claims.

To prevent customers from paying those costs, Idaho Power is proposing a solar integration charge that would be discounted from the amount the utility pays to solar developers.

Idaho Power proposes charges that gradually increase as solar generation increases. It proposes that developers pay about 40 cents per megawatt-hour when there is 100 megawatts or fewer of solar generation on Idaho Power's system. That cost increases to $1.50 per MWh when solar penetration is between 100 and 300 MW; $2.80 per MWh at a solar penetration of between 300 and 500 MW; and $4.40 per MWh at a solar penetration of between 500 and 700 MW. Those proposed amounts are for contracts signed this year and would gradually change during the length of the sales agreement.

The rapid growth of wind development and solar potential "had led to the recognition that Idaho Power's finite capability for integrating variable and intermittent generation is nearing its limit," the company claims in its application. "Even at the current level of wind generation ... dispatchable thermal and hydro generators are not always capable of providing the balancing reserves necessary to integrate variable generation," the company claims. "This situation is expected to worsen as wind and solar penetration levels increase, particularly during periods of low customer demand."

Commission adopts updated expenses developers pay to integrate wind into grid

Case No. IPC-E-13-22, Order No. 33150

Oct. 16, 2014 – The commission adopted updated rates to be charged wind developers who sell energy to Idaho Power Company to account for the utility's expense of integrating the wind onto its distribution and transmission system. The commission also approved a new method for calculating the wind integration charge.

"We find that the current mechanism for recovery of integration costs has resulted in under-collection of the actual costs required to integrate wind onto Idaho Power's system," the commission said. That is not in the best interest of Idaho Power ratepayers because expense to integrate wind that is not paid by wind developers is borne by customers.

In seeking the updated rates, Idaho Power said its ability to integrate wind into its system was nearing its limit. The utility has about 678 megawatts of wind capacity on its system now, 505 MW of that coming online since 2010. The integration rate has not been updated since 2007.

The intermittency of wind forces Idaho Power to modify its system operations to ensure transmission grid reliability. The utility must provide reserves from other resources -- such as hydro or natural gas -- that can increase or decrease generation on short notice to offset changes in wind generation. The effect of having to use other resources as operating reserve restricts those same resources from being economically dispatched to their fullest capability, resulting in higher power supply costs passed on to customers. The federal Public Utility Regulatory Policies Act (PURPA) requires Idaho Power to buy the wind from qualifying renewable energy projects.

Under the previous method, the wind integration charge was calculated by using a percentage of the avoided-cost rate set by the commission. The avoided-cost rate is the rate paid to renewable energy developers based on the cost the utility avoids by not having to generate the power itself or buy it from another source.

However, Idaho Power claimed that basing the integration charge on the avoided-cost rate has no relation to the actual costs of the additional reserves needed to integrate variable resources on its system.

Under the new method approved by the commission, wind developers will pay a tariff rate that is not based on a percentage of avoided-cost. Instead, the rate is established in a tariff that increases as the utility's overall wind penetration level increases because costs increase as more wind is added to the system. However, an increase to the integration rate when wind generation hits specific thresholds is applied only to new projects as they sign on. The rate each developer pays is determined at the signing of the contract so that developers have certainty as to what they will pay over the term of what is typically a 20-year contract.

For example, at the utility's current wind penetration level of between 600 MW and 700 MW, a developer of a project that signs in 2014 would pay an integration rate of $11.99 per megawatt-hour. For a non-levelized contract, that rate increases to $21.03 per MWh through the contract's end at 2033. The integration rate increases for new projects for every 100 MW of additional wind penetration up to 1,100 MW.

Intervenors representing the Renewable Northwest Project and the American Wind Energy Association said Idaho Power's proposal results in rates that are too high because the method it uses to calculate its reserve requirement to accommodate wind results in a reserve three times greater than necessary. The intervenors said the utility is not using actual wind integration expense to calculate the integration rate, but instead is using costs associated with having to re-sell surplus wind energy that PURPA compels Idaho Power to buy even when the wind is not needed.

The commission said the intervenors are not taking into account other costs the utility incurs because of PURPA's must-buy requirements. "We find that if a utility incurs additional operational costs as a result of having to balance intermittent, must-take PURPA generation, those costs are reasonably classified as integration costs," the commission said. "It is also in accord with this commission's position that PURPA transactions should not harm ratepayers."

Electric rate adjustments

Commission OKs 1.7% annual adjustment increases, but will open cases to further review PCA and FCA

Case No. IPC-E-14-03, Order No. 33047 and Case No. IPC-E-14-05, Order No. 33049

June 2, 2014 – Rates increased slightly effective June 1 for Idaho Power Company customers as part of the utility's Annual Adjustment Mechanism, which covers power expense and costs related to energy savings programs that change from year to year.

The Annual Adjustment Mechanism is updated every June 1 and consists of two primary components, the Power Cost Adjustment (PCA) and the Fixed Cost Adjustment (FCA). The adjustments can be an increase or decrease depending on circumstances.

For a residential customer who uses the company's average of 1,050 kilowatt-hours per month, the increase to both adjustments will total about $1.77 per month, or about 1.7% above current rates.

Power Cost Adjustment

Since 1993, the PCA 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 hydropower facilities, Idaho Power's actual cost of providing electricity varies depending on changes in Snake River streamflows. Other costs that change each year are the market price of power, fuel costs, transmission costs for purchased power and the revenue it earns from selling surplus power.

Power supply expenses for this PCA year (April 1, 2013 to March 31, 2014) were $27.1 million above the amount already collected from customers. To offset a larger increase, Idaho Power proposed to transfer $16.1 million of surplus funds in the Energy Efficiency Rider account toward the PCA, reducing the amount owed by customers to $11.1 million. The increase was offset further by $7.6 million allowed customers from a revenue sharing plan created by the company and the commission about five years ago. These steps reduced the overall PCA increase to 0.56% for residential customers. The average increase for all customer classes combined is 1.04%.

The Idaho Conservation League opposed transferring energy efficiency rider funds to offset the PCA because it would mask true power costs and send an incorrect price signal to customers on the need to conserve. Other parties, such as the commission staff and the Industrial Customers of Idaho Power (ICIP), said the surplus rider funds should be used to offset the Energy Efficiency Rider on customer bills rather than the PCA.

The commission said it normally expects Idaho Power to use rider funds for energy efficiency purposes, "But, as customers have noted, this year's rate increase will cause a hardship for some customers." Further, a reduction in the energy efficiency rider adds unnecessary complexity to the case, the commission said. ICIP said the rider, now 4% of a customer's billed amount, should be permanently reduced to 3%. The commission said that issue would need to be taken up in a separate docket.

Less hydro generation and lower-than-expected surplus sales were the primary causes of more power supply expense this year. Idaho Power forecast 6.8 million megawatt-hours of hydroelectric generation in the PCA year, but generated only 5.7 million MWhs through March. When there is less hydro generation, the utility must use more expensive resources to serve its customers. In a normal year, Idaho Power gets 50.7% of its electricity from hydro generation. During the 2013-14 PCA year, the company claims it generated only 38.1% from hydro sources.

Even though snowpack levels in the basins above Brownlee Reservoir have improved to near normal levels, reservoirs further upstream from Brownlee are at significantly lower than normal levels.

Less hydro generation also resulted in lower-than-expected surplus sales. Idaho Power anticipated $98.5 million in power sales, but realized only $66.8 million. Ninety-five percent of the revenue from off-system sales is shared with customers and applied against the annual PCA.

Commission staff raised concerns about some of the methods the company uses to compute the PCA deferral balance that staff said could have reduced the PCA by $14.2 million. Because the adjustment calculations are complex and the parties had little time to review them, the commission allowed the requested deferral amount. However, the commission will open a new case to allow all parties to more closely examine commission staff claims.

The commission reminded customers frustrated by the rate increase that the PCA does not influence the company's profits and can be used only to pay down already incurred power supply expense. The company's normal power costs are already recovered in base rates. The PCA recovers only above-normal costs the company incurs to provide power to its customers. If those variable expenses are below normal, customers get a one-year credit. "The company is supposed to request only its actual power costs and the commission and its staff work to ensure that the company only recovers those actual power costs," the commission said.

The new PCA rate for residential customers will be, slightly less than a half-cent per kilowatt-hour at 0.485 cents.

Fixed Cost Adjustment

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.

Idaho Power PCA Over the Years

2003 – 18.9 percent **decrease.** $81.3 million.
2004 – No change. $70.8 million.
2005 – No change. $73.1 million.
2006 – 19.4 percent **decrease**. $-46.8 million credit.
2007 – 14.5 percent increase. $30.7 million.
2008 – 10.7 percent increase. $106 million.
2009 – 10.2 percent increase. $194 million.
2010 – 6.5 percent **decrease**. $41.9 million.
2011 – 4.8 percent **decrease**. $50.4 million.
2012 – 5.1 percent increase, ($43 million) but that is offset from a revenue sharing agreement for a net increase to customers of **1.7 percent**.
2013 – 15.3 percent increase. $140 million.
2014 – 1 percent increase, $27.1 million

Before the FCA, Idaho Power did not have financial incentive to invest in energy efficiency because it lost revenue as consumption declined. Even though consumption may decline, fixed costs to serve customers do not. To remove that disincentive, the FCA was created to allow the utility to recoup its fixed costs.

The FCA has helped make it possible for Idaho Power to create about 30 programs that increase efficiency and reduce demand on its system, especially during peak periods when demand is highest and most expensive to both company and customers.

If the actual fixed costs recovered from customers by Idaho Power 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, customers get a credit. Last year's FCA was an average 27-cent per month decrease. This year, the company proposed an increase in the FCA rate of about 1.2% for residential customers to 0.2913 cents per kWh, up from 0.177 cents. The rate for small-business customers increases to 0.3709 cents per kWh, up from 0.226 cents.

As in the PCA case, commission staff and other parties found what they perceive to be flaws in the FCA mechanism. As a result, the commission will open a new case to investigate the issues raised. Among those are the way the FCA mechanism is calculated using averaged instead of actual weather conditions, using a median rather than an average number in customer counts, calculating the increase and the 3% cap on FCA increases using forecasted sales and revenues, and concern that residential and businesses classes may be subsidizing other customer classes.

Commission staff said the FCA may no longer be serving its intended purpose. The company's energy savings did grow rapidly during a 3-year pilot phase for the FCA, peaking in 2010 before dramatically dropping off in 2013. Idaho Power said it continues to aggressively pursue savings programs and that customer participation was up in 2013. The decline in energy savings, the company claims, is due to a change in the way savings are measured.

Idaho Power claims that opening a new case to examine the FCA mechanism is not necessary because the program received a review when the commission converted it from pilot to permanent status in 2013.

The commission said making the program permanent did not mean it would not be subject to review. "When staff, other parties, or the commission have serious concerns that the FCA is not working as intended, or may be allowing the company to over-recover its fixed costs to the detriment of customers ... a timely review is critical," the commission said. "We will continue to monitor the FCA results each year. If these reviews suggest clearer, more equitable refinements of the FCA, we will not hesitate to implement them."

Idaho Power revenue sharing program extended five years

Case No. IPC-E-14-14, Order No. 33149

(Oct. 10, 2014) – The Commission approved a proposed settlement to extend for another five years a program that allows Idaho Power Company to use its accumulated investment tax credits to shore up its rate of return and also share revenue with customers when that return exceeds certain levels.

The settlement was proposed by Idaho Power, commission staff and parties representing irrigation and industrial customers.

The revenue sharing program, in place since 2009, ensures the utility will meet at least a 9.5% return on equity while, at the same time, sharing with customers portions of revenue earned beyond a 10% ROE. The commission said the mechanism will provide customers an opportunity for future rate relief while also increasing the potential for rate stability.

The program allows Idaho Power to accelerate up to $45 million in investment tax credits over a five-year period, but no more than $25 million can be used in a single year. The tax credits may be used when the company's return on equity falls below 9.5%. If the return exceeds 10%, the company shares a portion of those revenues with customers. The program provides the company an opportunity to achieve earnings near its authorized rate of return in years when revenue from rates alone would not provide that same opportunity.

Since the revenue sharing program began in 2010, Idaho Power's return on equity has not fallen below 9.5% so the tax credits have not been accelerated. However, customers were provided more than $93 million in benefits under the revenue sharing provision either as a direct offset to rates or as an offset against future rates.

Idaho Power receives income tax benefits based on the level of its capital investment in generation plant and other facilities. These accumulated deferred investment tax credits (ADITC) are typically spread over the book life of the associated plant investment – which can sometimes be 30 years or longer – and used to reduce income tax expense included in customer rates during that period. As part of a 2011 moratorium on base rate increases, Idaho Power and other parties approved a settlement that allowed the utility to shore up its earnings by accelerating up to $45 million of investment tax credits.

The extension of the mechanism proposes that if Idaho Power's ROE is between 10% and 10.5%, customers will get 75% of the of the excess amount and the company would get 25%. The customers' share would be provided in the form of a rate credit to the Power Cost Adjustment (PCA) which becomes effective every June 1.

If earnings exceed 10.5%, three-fourths would again be shared with customers and one-fourth with the company. Fifty percent of the customer share would be applied against the PCA while the remaining 25% would be an offset to the amount customers contribute to the company's pension balancing account.

Up until the revenue sharing mechanism started in 2010, Idaho Power had not been able to earn its authorized rate of return for the previous decade in both its Idaho and Oregon jurisdictions. Customers benefit even if there is not a revenue sharing, the company claims, because an ROE of 9.5% reduces the company's cost of capital, which affects the rates customers pay. The positive ROE also improves the company's access to working capital for short-term financing needs.

The company agreed to continue to make its year-end earnings results available for audit by the commission staff and the settlement further provides that a copy of the audit report may also be made available to others parties to the settlement during the annual Power Cost Adjustment review. Those parties included Idaho Power, commission staff, the Idaho Irrigation Pumpers Association and the Industrial Customers of Idaho Power.

Avista annual electric adjustment is an increase

Case No. AVU-E-14-06, Order No. 33140

Oct. 1, 2014 – Electric rates for customers of Avista Utilities increase 4.2% effective Oct. 1, 2014.

The variable portion of electric rates go up or down every year based on the previous year's variable costs to serve customers.

The annual Power Cost Adjustment (PCA) changes every year based on: 1) streamflows, 2) fuel costs, 3) the market price of power and 4) revenue and expenses related to contracts with power suppliers.

During years when variable expenses are less than what is already included in rates, customers get a one-year rate credit or decrease. During years when variable expenses are greater than anticipated, customers get a one-year surcharge. Avista's earnings, dividends to shareholders or employee salaries are not increased by the PCA or PGA. Variable electric supply expense is kept in a deferred account audited by the commission, to ensure the expenses were necessary to serve customers and used only to pay for power supply expense.

While the PCA recovers variable costs of serving customers, fixed costs and some variable expense is included in base rates. Variable rates plus base rates make up the vast majority of customers' overall rate.

Avista's PCA increase recovers $7.7 million in power supply expense needed to serve customers that is not already included in rates. Further, a $4.6 million credit that occurred as a result of last year's PCA decrease expired this year. For a residential customer who uses Avista's average of 930 kWhs per month, an average monthly bill would increase by $3.76, from $81.88 to $85.64.

More than half of the PCA amount is attributable to $4.1 million in power Avista had to provide to replace the power lost as a result of a forced outage at the Colstrip coal plant in eastern Montana from July 1, 2013 to Jan. 22, 2014.

Intervenors in the case, including Clearwater Paper Corporation and Idaho Forest Group LLC, said that portion of costs should not be included in the PCA, pointing to a 2004 commission order that denied Idaho Power Company recovery of all the expenses related to an outage at the Valmy coal plant in Nevada.

However, the commission said the Valmy outage differed than the Colstrip incident. The undisputed evidence in that case showed that the Valmy outage was caused by an apparent failure to follow established safety procedures, a lack of proper supervision and poor communication, the commission said. In contrast, a third-party "Root Cause Analysis," determined that the

Colstrip outage could not have been avoided.

Environmental groups, including the Snake River Alliance, Idaho Conservation League and Sierra Club, said the commission should take more time to do its own study to determine if the Root Cause Analysis is valid. However, the commission said that the independent study, plus discovery conducted by Clearwater Paper and the Idaho Forest Group, all determined that there is no evidence the company imprudently incurred the Colstrip replacement power costs.

The environmental groups noted that this is the second major outage at the Colstrip unit in the last five years and questioned the wisdom of continued reliance on Colstrip coal. The commission said the extent to which Avista continues to rely on Colstrip is beyond the scope of the PCA proceeding. "The PCA is a cost tracker, and a PCA case narrowly focuses on whether a utility should increase or decrease its rates to reflect its tracked, actual power supply costs," the commission said.

Clearwater Paper argued it is paying more than what it costs Avista to serve it and proposed that $500,000 of its PCA charge be allocated to other customer classes. The commission denied Clearwater's request, noting that the cost-of-service study to which Clearwater points is based on a 2012 rate case and that an updated study could show different results.

Other contributors to the PCA increase included:

- The Palouse Wind project in eastern Washington came online during 2013, adding $2.17 million to power supply expense.
- A 19% increase in retail electric demand resulted in an additional $1.3 million in power supply expense.
- Clearwater Paper in Lewiston chose to use its own generation, which reduced anticipated purchases from Avista by about $2.3 million.

Commission adopts Avista rate settlement that leaves current base rates in place until 2016

Case No. AVU-E-14-05
AVU-G-14-01, Order No. 33130

Sept. 19, 2014 – The Commission adopted a settlement of an Avista Utilities' rate application that states the utility cannot increase electricity or natural gas base rates until Jan. 1, 2016, at the earliest.

Two customer credits that expire on Jan. 1, 2015 would have resulted in increases for both electric and natural gas customers, but the parties to the settlement proposed other means to make up for revenue lost due to the credits' expiration. A commission staff investigation said the settlement, rather than a fully litigated case, is in customers' interest because Avista may have justified increases of about $3.5 million in increased electric revenue and $200,000 in natural gas revenue.

A one-time credit resulting from a previous agreement between Avista and the Bonneville Power Administration expires on Jan. 1, 2015, which would have resulted in a 1.3% increase. A second credit to natural gas customers also expires on Jan. 1, and that would have resulted in a 1.7% increase in natural gas rates.

Those increases were eliminated by using funds from a revenue sharing program Avista has with its customers. If the consolidated earnings from both Avista's electric and natural gas sectors exceed 9.8%, half those earnings are deferred to future credits for customers the following year. If earnings are below 9.5%, Avista is allowed to apply previous years' earnings' deferral to move its earnings up to 9.5%.

The settlement applies a portion of Avista's 2013 deferral for earnings above 9.8% ($3.2 million) against the BPA credit expiration. The remaining $713,000 in customers' share of 2013 earnings is proposed to be applied against Avista's annual Power Cost Adjustment (PCA) now before the commission in a separate docket.

The increase that would have occurred when the natural gas credit expires will be paid for by $440,000 in revenue sharing and from a $653,000 balance in the natural gas Energy Efficiency account.

The settlement provides that 80% of expenses (up to $3.3 million) related to Avista's new customer information system, Project Compass, be deferred until 2016. That deferral is due in part to the uncertainty of the in-service date for the new billing and customer information system. The settlement also defers to 2016 a three-year amortization of $1.25 million ($418,000 per year) of expenses related to operations of the Coyote Springs 2 natural gas plant near Boardman, Oregon and the Colstrip 3 and 4 coal generating plants in southeastern Montana.

The settlement does not include increases that could come from Avista's yearly PCA or Purchased Gas Cost Adjustment (PGA). The settlement includes only base rates that apply primarily to Avista's fixed costs.

Parties to the base rate settlement agreement include Avista, commission staff, the Clearwater Paper Association, Idaho Forest Group, the Idaho Conservation League, Snake River Alliance and the Community Action Partnership Association of Idaho (CAPAI), which represents customers on low- and fixed-incomes.

CAPAI said the settlement was in the best of low-income customers and supported a requirement that interested parties meet before Oct. 14 to review Avista's conservation programs for low-income residential customers.

The Snake River Alliance also supported the settlement but expressed concerns about opportunities for public participation when rate cases are settled rather than fully litigated.

Rocky Mountain Power ECAM is a 2.6% decrease

Case No. PAC-E-14-01, Order No. 33008

April 7, 2014 -- Rates for Rocky Mountain Power's eastern Idaho customers decreased by an average 2.6 percent on April 1 as part of the utility's annual Energy Cost Adjustment Mechanism (ECAM).

The Energy Cost Adjustment appears as a separate line-item on customer bills. The ECAM adjusts actual power supply expense from forecasted power supply expense. The ECAM must be adjusted annually because some of the cost Rocky Mountain Power incurs to provide energy to its customers vary from year to year. These include expenses for fuel and for power purchased from the wholesale market. Also, the revenue the utility earns from its power sales changes annually. Rocky Mountain forecasts what those amounts may be and includes that forecast in base rates. Because the forecast is never precisely correct, there is an annual true-up of forecasted power supply expense to actual power expense. When the actual expense is greater than that included in base rates, customers get a one-year surcharge. When actual power supply expense is less than anticipated, customers get a one-year credit.

This year, the Idaho Public Utilities Commission approved an ECAM deferral balance of $7 million that represents a surcharge for all tariff customers. However, the surcharge is less than last year's surcharge meaning customers will be assessed about 2.6 percent less than the amount previously collected. Also approved are deferrals for large-contract customer Monsanto of $4.9 million and for Agrium of $400,000. They will receive 1.6 percent and 2 percent ECAM increases respectively. None of the money collected in the ECAM can be used to increase Rocky Mountain Power's earnings. The ECAM is kept in a deferred account audited by the commission and used only to pay power supply expense not already included in base rates.

The total deferral balance approved by the commission of $12.23 million is less than the company's originally proposed $13.2 million, resulting in rates lower than those proposed by the company. This is the third consecutive year the ECAM is either no change or a decrease for tariff customers.

The largest factor driving power supply costs down was reduced natural gas expense of 18 percent. That fuel price decrease moderated increases in other power supply expense categories including:

- A 41 percent decrease in revenue from wholesale power sales, largely due to the fact that wholesale market prices were 12 percent lower. Ninety-percent of the revenue from wholesale power market sales is shared with customers, while the company retains 10 percent. The utility can sell into the wholesale market only when the company is generating surplus power after having met customer demand;

- A 9 percent increase in purchased power expense;

- An 11 percent increase in fuel expense related to servicing the utility's coal plants;

- A significant decline in revenue from the utility's sales of Renewable Energy Certificates (RECs). The company fell far short of its forecasted REC sales of $6.5 million, realizing only $1.3 million due to REC market prices being significantly lower.

The commission also directed Rocky Mountain Power, commission staff and Monsanto to participate in workshops to resolve an issue over how the "wholesale line loss adjustment" is calculated. As power is transported over the utility's transmission lines, there is always some line loss. The adjustment determines how much of the associated cost should be allocated to the utility's Idaho customers. The parties differ over their interpretation of past commission orders as to how the wholesale line adjustment is applied.

Energy Cost Adjustment Mechanism 2010-14 for Tariff Customers

Year	Approved Power Supply Expense	ECAM charge	Net change
2010	$2 million	0.10 cents/kWh	
2011	$10.4 million	0.57 cents/kWh	5.8% increase
2012	$13 million*	0.57 cents/ kWh	No change
2013	$15.8 million*	0.57/cents/kWh	No change
2014	$12.2 million	0.32 cents/kWh	2.6% decrease

**While overall power supply expense increased in both 2012 and 2013, the increased costs were allocated to Rocky Mountain Power's contract customers, Monsanto and Agrium, and not to tariff customers.*

Rocky Mountain customers to get one-time credit from efficiency service over-collection

Case No. PAC-E-13-15, Order No. 32967

January 24, 2014 – The Commission approved a Rocky Mountain Power application to issue a one-time credit to customers of the eastern Idaho utility due to an over-collection in an account that pays for energy efficiency programs.

Customers pay a “Customer Efficiency Services” charge of 2.1 percent of their total billed amount every month. Heavy summer loads during 2012 and 2013 resulted in higher than forecasted revenues in that account. The commission granted the utility’s request to issue a one-time refund to customers that will be about $8.32 for the average residential customer. The amount of the credit will vary depending on the amount of energy use. The credit will be applied against either the February or March bill depending on each customer’s billing cycle.

The money collected in the rider account can go only toward funding cost-effective programs that increase energy efficiency. If the account collects significantly more than the company anticipated, it must either reduce the rider or refund customers. The rider has already been reduced from a high of 4.72 percent in 2010 to 2.1 percent today.

The one-time credit will not impact Rocky Mountain’s future expenditures in efficiency programs. Rocky Mountain anticipates that efficiency expenses will be remain constant this year with a forecasted increase in 2015.

The programs funded by the rider are designed to delay or eliminate the need for the utility to build new generation. All of the programs funded by the Customer Efficiency Services rider must pass cost-effectiveness tests that show customers would be paying more for electricity if the programs were not in place.

Rocky Mountain Power is surpassing its goals for energy efficiency. In 2012, the goal was to reach 8.5 million kilowatt-hours of savings and the company attained 10.54 million kWhs. As of September 30, 2013, the company had achieved 11.47 million kWhs of savings, already surpassing 2012 totals.

Demand-Side Resource Issues

2012 DSM: Idaho Power energy efficiency expense determined ‘prudent’ by commission

But commission concerned about possible “retreat” from DSM

Case No. IPC-E-13-08, Order No. 32953

(January 7, 2014) – The Commission determined that the vast majority of the $46.35 million that Idaho Power Company spent on energy efficiency and demand-response programs during 2012 was prudently incurred, but at the same time, directed Idaho Power to address perceptions that the utility is “retreating” from its commitment to programs that reduce electric demand.

The Commission determined that $46,092,000 of the $46,356,000 the company spent on the energy savings programs was prudently incurred, meaning they can be included as expense to be recovered through the 4 percent Energy Efficiency Rider or through the annual Power Cost Adjustment set every June 1. The commission’s annual prudency review of these programs does not immediately impact customer rates.

Idaho Power has 15 energy efficiency programs, two energy efficiency education programs and three demand-response programs, all of which are reviewed to determine cost-effectiveness. The programs must pass three cost-effectiveness tests to ensure that the cost of the programs does not exceed the benefit. One of the tests, the Total Resource Cost test, must show that all customers benefit from the programs, not just those who directly participate in them.

While the commission approved nearly all of the expense as prudently incurred, it took notice of Idaho Power’s decisions during 2013 to temporarily curtail the air conditioner cycling and irrigation load control programs and the decision to discontinue participation in regional energy conservation efforts. “We are concerned that the company’s recent actions have fostered a stakeholder perception that the company is retreating from its DSM (demand-side management) commitments,” the commission said.

The commission is concerned that some of these decisions were made without adequate input from Idaho Power’s Energy Efficiency Advisory Group, which includes stakeholders from customer and environmental sectors. “Based on the record in this case, we remain concerned that the company does not fully utilize the EEAG and proactively and collaboratively involve the EEAG in DSM-related decisions,” the commission said. It directed the company to file a report before the end of

February outlining the company's perspective on the EEAG's purpose and value, whether or not it is working and how it could be improved.

The air conditioner cycling and irrigation load control programs have been resumed for the 2014 summer season after the commission, company and interested parties agreed on revisions to make the programs more cost effective.

In late 2012, Idaho Power said it was pulling out of the regional Northwest Energy Efficiency Alliance (NEEA) after the contract between the two expires later this year. Idaho Power also declined to help fund research efforts at the CAES Energy Efficiency Research Institute (CEERI). CAES is the Center for Advanced Energy Studies, headquartered in Idaho Falls. Idaho Power said it declined to fund the research because it could not agree with the participating universities about publication rights associated with the research. The commission said Idaho Power's decisions regarding NEEA and CEERI may have merit, but the company should have consulted with EEAG in reaching those decisions.

Idaho Power's 15 energy efficiency programs are funded primarily through a 4 percent Energy Efficiency Rider on customer bills. An energy-efficiency program is one in which less energy is used to perform the same function. Idaho Power said it spent about $31.8 million on energy efficiency programs and that those programs provided 170,228 megawatt-hours in energy savings during 2012. 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 wells as creating efficiencies in commercial and industrial buildings.

Expenses related to Idaho Power's three demand-response programs are included in the annual Power Cost Adjustment. A demand-response program is one that shifts energy use to non-peak times of day, reducing demand on a utility's generation system. Idaho Power incurred nearly $14.5 million in expense for those programs and, according to Idaho Power, provided about 438 MW of capacity during 2012. One megawatt is enough power to energize about 650 average-sized homes. Demand-response programs included one that credits irrigators for shifting use of their irrigation systems to non-peak periods of the day and an air conditioner cycling program that offers residential customers a monthly credit for agreeing to let the utility remotely cycle their air conditioning during the summer months.

2013 DSM: Idaho Power expenditures toward conservation programs are prudent

Case No. IPC-E-14-04, Order No. 33161

(Nov. 13, 2014) – The Commission determined that Idaho Power's $26 million of investment in demand response programs during 2013 was prudently incurred. The programs are primarily funded through a 4 percent Energy Efficiency Rider on customer bills.

Idaho Power's 18 energy efficiency programs and educational initiatives contributed toward an estimated 107,284 megawatt-hours in energy savings during 2013. One demand-response program resulted in a 48-megawatt reduction in demand on Idaho Power's generation system. *(An energy-efficiency program is one in which less energy is used to perform the same function. A demand-response program is one that shifts use to non-peak times of day, reducing demand on a utility's generation system. Combined, all these programs are called Demand Side Management programs, or DSM.)*

While the commission said the company's expenditures were prudently incurred, it withheld judgment on claims by commission staff, the Idaho Conservation League and the Industrial Customers of Idaho Power that the company's commitment to DSM "seems to be waning," and it allegedly does not do enough to market the programs to customers.

The commission chose to rule on the prudency issue alone, determining that the other issues raised are significant enough to warrant a more in-depth review before Idaho Power submits its next Integrated Resource Plan filing. That plan, filed every two years, lays out how the company will meet customer demand over the next 10 and 20 years.

The company's energy savings and demand reduction are down from the 2012 totals of 170,220 MWh in energy efficiency savings and 438 MW in demand response. Idaho Power says part of that reduction is attributable to third-party evaluators' more stringent methods of measuring the programs to determine their effectiveness and due to the one-year suspension of two demand-response programs. Further, the company notes, customer participation is up even though actual energy savings are down.

"The commission is cognizant of the recent decline in energy savings ... and notes that Idaho Power issues a strong rebuttal of these claims, offering several reasons to explain the recent decline in its DSM expenditures and a defense of its marketing efforts," the commission said. "We are encouraged that the reply comments seem to demonstrate the company's renewed interest in procuring all cost-effective DSM."

Some of Idaho Power's energy efficiency programs include offering rebates to customers for increased use of heating and cooling efficiencies, energy efficient lighting and creating efficiencies in commercial and industrial buildings. The one demand-response program used during 2013, called Flex Peak, allows large commercial and industrial customers to reduce their electric loads for short periods during peak summer days. The demand-response programs suspended were a residential air conditioner cycling program and an irrigation control program that allowed volunteer customers to shift some air conditioning and irrigation to non-peak periods of the day. Both those programs have been renewed but with changes to make them more cost-effective.

Avista Utilities' expense to implement efficiency programs declared prudent

Case Nos. AVU-E-13-09, Order No. 33009

(April 11, 2014) – The Commission determined that Avista Utilities' prudently incurred $25.17 million in expense related to its electric and gas efficiency programs during 2010-12.

The commission's finding means those expenses can be included in the electric rider of 0.245 cents per kilowatt-hour on customer electric bills. The gas rider is temporarily zeroed out because low natural gas prices render the expense related to the gas efficiency programs less prudent. The prudency finding does not impact customer rates.

The electric efficiency programs provided more than 109,100 megawatt-hours of savings during 2010-12. Natural gas efficiency programs resulted in 950,822 therms not being used.

The commission determined that $25.17 million of the $25.4 million the company spent on energy and natural gas efficiency programs was prudently incurred.

The 30 programs funded by the rider must pass cost-effectiveness tests that demonstrate all customers benefit, not just those who participate in the programs.

One test, the Total Resource Cost test, measures whether the total costs in Avista's north Idaho service territory decrease as a result of the programs. That test showed that for every $1 invested in the programs, the benefit to all customers is $1.91.

Some of the programs for residential customers include financial incentives for installation of high-efficiency equipment, compact fluorescent lamps, refrigerator recycling, weatherization, and electric-to-natural gas conversions. Commercial and industrial customers who participate can take advantage of customized, site-specific programs.

The commission did not include about $100,000 Avista paid the state Department of Energy Resources for efficiency projects at schools because Avista paid the incentives without verifying that the efficiency measures had been installed and without receiving contractor receipts or invoices to confirm the purchases and labor associated with the projects. The commission believes the efficiency measures were purchased and installed and will allow those expenses to be included in the prudency determination once verification is provided. The commission also didn't include $14,120 paid to Lewis Clark State College for the same reasons.

The commission also said Idaho customers should not have to pay for more frequent third-party evaluation required by Washington state, also part of Avista's service territory. Although the evaluations provide some benefit to Idaho customers, Avista agreed to shift about $100,000 from the Idaho rider to the Washington rider. The commission also encouraged Avista to abide by the 50 percent cap on site-specific efficiency projects' cost and to more carefully manage its labor costs related to all the efficiency programs' implementation.

Overall, the commission expressed satisfaction with Avista's management of the programs, which provide cost benefits to customers. "Like commission staff and the Idaho Conservation League, we applaud Avista's longstanding 'top down' commitment to demand-side management and stakeholder involvement in energy efficiency issues," the commission said.

Rocky Mountain prudency application is for $26 million in demand-side resource expense

Case No. PAC-E-14-07, Order No. 33122

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

(Oct. 24, 2014) – Rocky Mountain Power's application for a prudency determination on nearly $26 million of the company's investment in demand-side management (DSM) programs during 2010-13 was not completed when this report was prepared.

DSM generally refers to utility activities and programs that encourage customers (the "demand" side as opposed to the "generation" side) to use less energy or shift use away from peak hours, thus reducing demand on Rocky Mountain's generation system. Customers pay for the programs through a rider that appears on customer bills as "Customer Efficiency Services." The rider is currently set at 2.1% of a customer's monthly billed amount.

The Commission's prudency review is to determine if the funds invested in demand-side programs were reasonable and beneficial to customers.

Rocky Mountain Power claims the programs 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 reduces power supply expense for all customers and eliminates or delays the need to build new generating facilities.

Three of the programs are available 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 customers 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 target commercial, industrial and agricultural customers. These include "FinAnswer Express" to help commercial and industrial customers improve the efficiency of their lighting, HVAC, electric motors, building envelopes and other equipment. “Energy FinAnswer” is available to commercial and industrial customers in excess of 20,000 square-feet and includes incentives for improvements to HVAC systems, motors, refrigeration, lighting and other equipment. “Agricultural Energy Services” is designed to improve overall efficiency of irrigation systems. A final program for qualifying volunteer irrigation customers offers financial incentives to irrigators if they irrigate during non-peak hours.

Rocky Mountain reports that five of the programs were cost-effective in all years, one during two of the three years and another, Low Income Weatherization was not cost-effective during the three-year period. The company says it has taken action to improve the cost-effectiveness of that program.

Rocky Mountain Power, a division of PacifiCorp, serves 73,500 customers in eastern Idaho.

Other electric issues

Commission adopts tariff revisions to accommodate industrial expansions

Case No. IPC-E-14-01, Order No. 32982

(March 3, 2014) -- Large industrial customers of Idaho Power Company who must pay for new substation or transmission facilities to serve their increased electric load may receive upfront credits for each year up to five years to help them meet the expense of the expanded facilities.

The Commission approved a revision to Idaho Power's tariff for industrial customers that will make it more affordable for industrial customers requiring Idaho Power to upgrade transmission or substation facilities needed to serve one customer.

Builders of residential and commercial developments already receive an allowance under the "Rule H tariff" to help pay for distribution-related line extensions. The cost of new or expanded facilities is typically shared between the new customer and the utility, lowering the cost barrier customers face when seeking new or additional line extensions. The allowance makes it possible for the amount of upfront charges to be paid by the customer to be reduced by permitting the utility to collect a portion of the expense over time.

When Glanbia Foods, Inc., a Gooding cheese plant, applied for a Rule H allowance last year, Idaho Power claimed the allowance applied to only distribution voltage equipment, not new substations or high-voltage transmission lines. Glanbia is funding $8.3 million in Idaho Power facility improvements ($4.5 million for a 10-mile transmission line and $3.8 million for a substation) and increasing its annual power bill to Idaho Power by about $7 million.

Glanbia requested an allowance of $2.3 million and also asked for entitlement to future potential "vested interest" payments. Vested interest payments are provided the party that paid for the initial expansion as new customers who are using the same facilities are later added.

In the Glanbia case (IPC-E-13-09), the commission eventually approved an allowance of $1.25 million using a formula allowing it $65,734 per megawatt of the plant's projected load of 19 MW. The commission also allowed vested interest payments to be directed to Glanbia if new customers connect to the Glanbia property substation facilities within the next five years.

As a result of the Glanbia case, the commission directed Idaho Power to propose a substation and transmission allowance and vested interest provision for large industrial customers.

In this case, the commission adopted Idaho Power's proposed allowance of up to $65,480 per MW multiplied by the customer's projected increase in load for each year up to five years. If the load used by the new customer decreases, it would receive less of an allowance. The tariff revision is effective immediately.

Commission OKs Idaho Power sales agreement with Bannock County landfill-to-gas plant

Case No. IPC-E-13-24, Order No. 32986

(March 3, 2014) -- The Commission approved a 20-year sales agreement between Idaho Power Company and Bannock County's landfill-to-gas energy plant near Pocatello.

Bannock County plans to initially install a 1.6-megawatt generation unit and then install another 1.6-MW unit within five years. The scheduled operation date for the first phase is May 1.

The Bannock County facility qualifies under the provisions of the Public Utility Regulatory Policies Act of 1978, or PURPA. The act requires that electric utilities offer to buy power produced from qualifying small-power producers. The rate to be paid small-power producers is determined by the commission and is called an "avoided-cost rate" because it is to be equal to the cost the electric utility avoids if it would have had to generate the power itself or purchase it from another source.

The agreement includes "non-levelized" payments from Idaho Power to Bannock County that gradually increase throughout the life of the contract. Beginning this year, the avoided-cost rate for projects of this type is $42.35 per megawatt-hour, though that amount is adjusted slightly downward during light-load hours of the day and season and upward during heavy-load hours and seasons. In 2033, at the end of the contract, the price would be $99.72 per MWh.

Commission returns contract dispute back to Idaho Power and Simplot to resolve

Case No. IPC-E-13-23, Order No. 33038

(May 21, 2014) -- The Commission denied a proposed contract between Idaho Power Company and one its largest customers, the J.R. Simplot Company's new potato processing plant in Caldwell, until the two parties can resolve disputes over liability and price.

The plant will require enough energy, in excess of 20,000 kilowatts, to place it in a customer class that requires a special contract with Idaho Power for power delivery. Simplot objects to Idaho Power language that places limits on both parties' direct liability and waives damages for indirect or consequential liability. Further, Simplot maintains the formula Idaho Power uses to calculate the rate Simplot would pay Idaho Power is outdated.

Idaho Power argues that limits on liability are needed to protect customers. "Today, the electric grid faces a variety of challenges to maintaining its reliability, from integrating increasing amounts of intermittent generation to acts of sabotage," the utility claims. "The grid's technological complexity results in potential service failures unrelated to human error. In light of this complexity, it is very difficult for a jury to distinguish between human error, negligence and failures of technology beyond Idaho Power's control." Idaho Power claims the liability limits protect the utility and customers from catastrophic loss.

Simplot argues that previous Idaho Supreme Court decisions have held that public utilities should not be immune from damage claims because customers cannot choose between competing suppliers of electric power and are, thus, "compelled to rely absolutely on the care and diligence of the company in the transmission of power. Idaho Power's proposed exculpatory language shielding it from virtually all liability is a violation of the public trust under which it serves."

In an order issued this week, the commission said exempting a public utility from the consequences of negligent conduct when the utility is charged with a public duty is not reasonable. "Idaho Power cannot abrogate its general duty to exercise reasonable care in operating its system to avoid unreasonable risks of harm to its customers."

However, while the commission said limits on "intentional tortious conduct or gross negligence" are not in the public interest, it is reasonable to consider limits on liability to an agreed-upon amount for a non-willful breach of duty.

Regarding the rate Simplot would pay Idaho Power, the utility proposed about 4.24 cents per kWh. Simplot proposed about 3.94 cents per kWh. Commission staff proposed using an average of rates charged all Idaho Power's special contract customers.

The commission rejected the staff's averaging proposal 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 commission directed the parties to renegotiate those portions of the proposed contract regarding liability and price based on the commission's findings in this week's order. The final proposed contract must still be approved by the commission.

Commission approves Avista stock issuance to allow purchase of Alaska energy company

Case No. AVU-U-13-01, Order No. 32991

(March 12, 2014) -- The Commission approved an Avista Utilities application to issue up to 7,250,000 shares of common stock to fund Avista's purchase of Alaska Energy and Resources Company.

AERC includes Alaska Electric Light and Power, which serves about 16,000 customers in Juneau and the surrounding borough. It is the oldest and largest investor-owned utility in Alaska. In addition to the electric utility, AERC also owns AJT Mining Subsidiary, a mining company that is currently inactive.

When the transaction closes, expected by July 1, AERC will become a wholly owned subsidiary of Avista, headquartered in Spokane. The transaction will not affect rates for Avista's 125,000 customers in north Idaho.

The commission's order specifies that Avista maintain its own operating books, records and subaccounts separate from AERC records and that Idaho commission staff have access to all books and records related to the transaction. Avista must also exclude any costs related to the merger from Avista's Idaho customers and file status reports with the commission regarding any pertinent quarterly financial information.

Avista reports that the purchase price at closing will be about $170 million, funded through the issuance of Avista common stock to the shareholders of AERC.

In 2012, Alaska Electric Light and Power had annual revenues of $42 million and 60 full-time employees. The utility has a firm retail peak load of 80 megawatts, nearly all of that generated by hydroelectric plants.

PUC accepts Avista Utilities' growth plan

Case No. AVU-E-13-07, Order No. 32997

(March 26, 2014) – The Commission accepted a long-range growth plan submitted by Avista Utilities, which serves about 125,000 electric customers in northern Idaho.

The Commission requires regulated electric and gas utilities to file an Integrated Resource Plan (IRP) every two years outlining how they anticipate meeting load growth over the next 20 years in the most cost-effective manner.

Avista has reduced its load-growth projections, from a forecasted 1.6 percent growth to 1.1 percent. That reduced growth will delay the need for a natural-gas fired plant by one year and eliminate the need for one of two natural gas plants that were projected for 2023.

Avista's plan says its own generation and its long-term contracts will provide enough energy to meet customer needs until 2020. The company may be short during peak winter periods in 2014-15 and 2015-16 but plans to meet those needs with market purchases.

A long-term capacity deficit does not happen until 2020. To address that deficit, Avista's IRP calls for the addition of an 83-MW simple-cycle combustion turbine natural gas plant in 2019. To meet growth beyond 2020, the plan calls for another 83-MW simple-cycle CT in 2023 and a 270-MW combined-cycle CT in 2026. Another 50-MW simple-cycle natural gas plant is anticipated for 2032.

Costs related to greenhouse gas emissions have been removed for the first time since Avista's 2007 plan. "Based on current legislative priorities and the President's Climate Action Plan, a national greenhouse gas cap-and-trade system or tax is no longer likely," the plan's executive summary states. Instead, the IRP forecasts some plant retirements to meet potentially new environmental regulations. Avista's current thermal resources include five natural gas plants, a wood-waste biomass facility, and 222 MW from part ownership of two units of the Colstrip coal plant in eastern Montana.

Environmental organizations say costs related to the Environmental Protection Agency's potential greenhouse gas regulations should not be removed. Further, the Sierra Club and the Montana Environmental Information Center claim the plan does not fully address the risks associated with the Colstrip coal plant and overestimates the cost of alternative resources to the Colstrip coal. The groups contend their appeal of the EPA's regional haze decision could cost Colstrip owners more than $100 million if the appeal is successful. Avista has 15 percent ownership of the Colstrip plant. Majority owner PPL Montana has announced plans to divest its interest in the plant.

The Snake River Alliance claims Avista is over-reliant on natural gas resources, exposing ratepayers to gas price volatility and uncertain supply. The SRA claims the utility's reliance on increased natural gas generation and only 19 megawatts from demand-reduction programs does not reflect a serious effort to reduce carbon emissions. Avista responds by saying its 2013 IRP is the first time that demand reduction programs pass cost-effectiveness tests and that the utility plans to study expanding its demand-response programs as part of its 2015 IRP.

In addition to its demand-reduction programs geared primarily to commercial and industrial customers, Avista's energy efficiency programs[1] currently decrease the utility's energy requirements by about 10 percent, or 125 average megawatts. Absent energy efficiency programs, Avista would be resource-deficient earlier than 2020. The company expects to achieve another 164

[1] Energy efficiency is using the same appliance or service to use less electricity (CFL lightbulb). Demand response is altering customer behavior in response to peak situations such as delaying consumption to non-peak periods, thereby reducing demand on an electric utility's generation.

aMW in energy efficiency over the next 20 years.

Avista said it invited more than 120 representatives from 45 organizations to meetings seeking input on the IRP and that the environmental groups who expressed concerns in this case did not materially participate or express concerns until filing their comments.

In its order, the commission encouraged the environmental and other interested groups to participate in the 2015 IRP process. The commission said it expects Avista to, "monitor federal developments, such as the promulgation of federal environmental regulations, and to account for their impact in its resource planning."

"As always, our acceptance of the company's IRP should not be interpreted as an endorsement of any particular element of the plan or any proposed resource acquisition contained in the plan," the commission said. "By accepting the company's filing, we acknowledge only the company's ongoing planning process, not the conclusions or results reached through that process."