Electrical Power in Idaho

Idaho residents consistently enjoy some of the least expensive electric service in the nation. According to data compiled by the Energy Information Administration, Idaho ranked 51st of the 50 states and District of Columbia in electricity rates during 2010. http://www.eia.gov/state/state-energy-rankings.cfm?keyid=18&orderid=1

Idaho Power Company

2010 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
394,132 Residential Customers/$0.0808
76,563 Commercial Customers/$0.0620
118 Industrial Customers/$0.0447

Avista Utilities

2010 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
105,286 Residential Customers/$0.0854
16,573 Commercial Customers/$0.0836
476 Industrial Customers/$0.0530

2010 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)

PacifiCorp/Rocky Mountain Power

56,842 Residential Customers/$0.0872
8,394 Commercial Customers/$0.0719
5,537 Industrial Customers/$0.0523

Summary of major electric rate cases

Three rate changes result in net decrease for Idaho Power customers

Customers of Idaho Power Company will be paying slightly lower rates beginning June 1. Three rate adjustments result in a net average decrease of 3 percent for all customer classes and about 1.45 percent for the company's largest class, residential customers.

The biggest reason for the overall rate decrease is the annual Power Cost Adjustment, which is an average 4.8 percent decrease for all customers (3.6 percent for residential customers). Two other adjustments, the annual Fixed Cost Adjustment (FCA) and a pension fund expense recovery announced May 19 are slight increases.

Power Cost Adjustment
Case No. IPC-E-11-06, Order No. 32250
The PCA tracks Idaho Power's annual power supply expense, which varies every year depending on water supply, fuel costs and market prices for power. The PCA is calculated, in part, by a forecast of the coming year's power supply costs. A second component of the calculation is a "true-up" of the preceding year's revenue forecast with actual power supply costs. The true-up ensures that customers aren't paying more or less than the company's actual power supply costs. Idaho Power's 2010-11 power supply expenses are $40.4 million less than the amount currently collected in the PCA account. As a result, the commission granted the company's request to reduce the annual PCA surcharge an average 4.8 percent.

Every year on June 1, the Power Cost Adjustment (PCA) results in either a one-year surcharge or credit to customers depending on the previous year's power supply costs. When snowpack and streamflows are normal or better, Idaho Power can generate more power from its hydroelectric projects. Hydro generation is less expensive for the company than generating from thermal sources or buying power from the regional market, which Idaho Power does during low-water years. When that happens, customers typically get a one-year increase or surcharge.

Also included in this year's power supply expense account is $10 million in Energy Efficiency Rider expense.

Fixed Cost Adjustment
IPC-E-11-03, Order No. 32251
The commission approved an average 0.74 percent increase to residential and small-business customers in this fourth year of Idaho Power's pilot Fixed Cost Adjustment program. Other customer classes are not impacted.

The FCA, implemented in 2007, allows Idaho Power to recover the fixed costs it loses when conservation programs result in lower power sales. However, the commission capped the increase in any single year at no more than 3 percent.

Without a mechanism like the FCA, there is a financial disincentive for Idaho Power to promote energy efficiency and conservation because it loses revenue when conservation results in power sales declining. Sometimes referred to as “decoupling” in the utility industry, the FCA decouples or separates Idaho Power’s fixed costs from its energy sales, assuring the utility will be able to recover its fixed costs as established in the most recent rate case regardless of how much energy customers save. If the company under collects its fixed costs of serving customers, customers get a surcharge. Conversely, if the company over collects fixed costs, customers receive a credit, as they did in the first year of the program. The commission capped the percentage increase that could be collected from residential and small-business customers at no more than 3 percent.

This year, Idaho Power under-collected $7.9 million in fixed costs from the residential class and $1.4 million from the small-business class.

When the commission initially approved the program, it did so as a three-year pilot. The commission denied Idaho Power’s 2009 request to make the program permanent until more questions about the program are resolved. However, the commission did agree to extend the pilot program another two years.

Pension plan recovery
IPC-E-11-04, Order No. 32248
As announced on May 19, the commission granted Idaho Power authority to increase its contribution to its pension plan from $5.4 million annually to $17.1 million and spread the increase over three years, resulting in a 1.39 percent increase for all customer classes.

Case No. IPC-E-11-08, Order No. 32426
December 30, 2011

Idaho Power increase is a net 3.44 percent

Base electric rates for customers of Idaho Power Company increase by 4.2 percent on Jan. 1, 2012. Part of that 4.2 percent is an increase in the monthly customer service charge from $4 to $5. However, there is also a 0.75 percent decrease to the energy efficiency rider, resulting in a net average increase of 3.44 percent.

The commission’s order approves a negotiated settlement between the utility, commission staff and customer groups representing all major customer classes.

In June, Idaho Power asked for an average 10 percent increase. The original application asked for an $81 million increase to annual revenue in light of more than $450 million the company invested in infrastructure since its last rate case in 2008. The settlement allows a $34 million increase to annual revenue.

Most of the reduction in revenue requirement was achieved by shifting $24 million in expense related to small-power projects to the Power Cost Adjustment mechanism made every June 1. Nearly $300,000 in expense related to turbine inspection was deferred and amortized over four years and about $436,000 for a Light Detection and Ranging survey was deferred and amortized over 10 years.

The revenue adjustments "reduce the magnitude of the proposed rate increases and benefit all customer classes," the commission said. "In particular, we note that the settlement stipulation represents a significant reduction – almost 60 percent – in the company's initially proposed rate increase." Randy Lobb of commission staff stated the settlement resulted in a "better outcome for customers than could reasonably be anticipated through litigation."

Idaho Power was allowed a 7.86 percent rate of return on its Idaho jurisdictional rate base of $2.35 billion. It requested 8.17 percent.

Parties to the settlement also agreed that there would be no increase in the winter for energy consumption within the third tier, which is above 2,000 kilowatt-hours per month. The commission said maintaining the third block non-summer rate of 8.46 cents per kWh will moderate the impact on customers who heat their homes with electricity. Rural Idaho customers who do not live near natural gas pipelines have few options to control winter use.

The commission conducted two customer workshops before the settlement and three public hearings and a technical hearing after the settlement was proposed. More than 100 customers submitted written comments, all opposed to the rate increase citing the weakened economy and adverse impacts on residential customers with low and fixed incomes.

Participants in the settlement representing primarily residential customers included commission staff and the Community Action Partnership Association of Idaho (CAPAI). Other participants included the Idaho Irrigation Pumpers Association, the Industrial Customers of Idaho Power, the Department of Energy, Micron Technology, the Idaho Conservation League, the Snake River Alliance, the Northwest Energy Coalition and Hoku Materials.

CAPAI did not sign the settlement mainly because Idaho Power has not agreed to increase its funding for a low-income weatherization program. CAPAI asked that the company increase its funding for the program by 125 percent, from $1.2 million to $2.7 million. The commission declined, stating concerns about cost-effectiveness. "Because ratepayers fund Idaho Power's weatherization programs, we have a responsibility to ensure these programs are cost-effective and designed to maximize benefits for all customers," the commission said. The commission will open a case and convene public workshops to determine the best methods for establishing the level of investment in low-income weatherization.

The commission deferred decisions about other issues on which the parties could not agree, including whether the Fixed Cost Adjustment rider on customer bills should become permanent. A final decision on the FCA will be made by March 30, 2012. The commission also did not decide whether overhead amounts for line extensions for customers requesting new service should be increased.

The energy efficiency rider, which is reduced from 4.75 percent of customer's billed rate to 4 percent, funds a number of conservation programs that reduce the need for Idaho Power to acquire additional generation or buy power from other providers. All of the programs funded by the rider must pass three cost-effectiveness tests that demonstrate customer rates would be higher without the programs in place. Because $11.2 million of those programs are being shifted into base rates, parties argued the rider should be decreased to as low as 3.4 percent. Others, including the Idaho Conservation League, Snake River Alliance and Northwest Energy Coalition, said the rider should remain at 4.75 percent because Idaho Power is still directed to continue to pursue all cost-effective energy efficiency and some "headroom" is needed to provide for planned growth in conservation programs.

When it filed the rate case in June, Idaho Power said it made significant investment in pollution control equipment in four units and upgraded a turbine in one unit of the Jim Bridger power plant, a coal-fired facility in southwest Wyoming. Idaho Power also completed construction of a new 500-kilovot Hemingway transmission station and the associated Hemingway to Bowmont 230-kV transmission line at a total cost of $54 million. The company also completed construction of the Long Valley Operations Center in Lake Ford to replace the existing McCall Operations Center.

Case No. IPC-E-10-27, Order No. 32217
April 1, 2011
Contact: Gene Fadness (208) 334-0339, 890-2712
Website: www.puc.idaho.gov

Commission rejects conservation funding settlement

A settlement among a number of parties to approve an Idaho Power Company application to shift about $20 million in expenses for conservation programs from the Energy Efficiency Rider currently on customer bills to base rates and to the annual Power Cost Adjustment has been rejected by state regulators.

The Idaho Public Utilities Commission said the issues raised in the settlement are more appropriately addressed in a general rate case, which is anticipated to be filed later this year. The commission also expressed concern that shifting some conservation program expense to other areas may result in a cost allocation to some customer classes that is not equitable.

Commission staff and conservation groups supported the settlement, while industrial customers opposed it. The industrial customers said that while shifting conservation program expenses from the 4.75 percent efficiency rider now paid by all customers to other areas may stop further increases in the rider and perhaps reduce the rider amount, customers would end up paying in other ways. The real impact, the industrial customers argued, would be the same as increasing the rider to 6.6 percent.

Parties that supported the settlement included Idaho Power, commission staff, the Idaho Conservation League, the Northwest Energy Coalition, the Snake River Alliance and the Community Action Partnership Association of Idaho, which represents primarily residential customers on lower and fixed incomes. A group representing irrigators did not oppose the settlement, but still did not sign it.

Proponents of the settlement contended that moving some conservation program expenses to base rates and some to the yearly Power Cost Adjustment puts conservation on the same level as acquiring generation from traditional supply-side resources such as coal and natural gas. Including some of that expense in base rates encourages Idaho Power to continue to pursue conservation programs by allowing it to earn a rate of return on some investment, proponents argued.

Idaho Power operates a number of demand-side management (DSM) programs that reduce demand on the company's generation needs during peak times of electrical use. The company also has a number of energy efficiency programs that reduce energy consumption through the use of more energy efficient lighting, appliances and industrial equipment. The cost of the demand-side and energy efficiency programs is recovered from customers through the Energy Efficiency Rider on customer bills, now set at 4.75 percent.

However, the revenue raised from the Energy Efficiency Rider is not keeping up with the cost of demand-side and energy efficiency resources. If changes are not made, the negative balance in the rider account will be $17 million by the end of this year and $30 million by the end of 2012. To pay off that negative balance in one year and continue funding programs at their current level, the rider would have to be increased from the current 4.75 percent to 7.5 percent of customer bills. To recover the balance in two years, the rider would have to be increased to 6.6 percent. The proposed settlement would have reduced the negative balance in the rider account to zero by early to mid-2012 and could result later on in a reduction in the rider.

Commission staff favored the settlement, stating that increasing the rider is "attracting unwarranted attention and criticism," resulting in Idaho Power not getting timely recovery of demand-side costs needed to promote acquisition of cost-effective conservation programs.

Parties to the settlement proposed that the expense of three major demand-side programs, including one for irrigators and one for residential customers with air conditioners, be shifted to the annual Power Cost Adjustment. They proposed that expenses related to energy efficiency programs for Idaho Power's large commercial and industrial customers be capitalized and included in base rates. Doing so would allow the company to earn a rate of return on demand-side resources just as it does on supply-side resources.

The commission decision to reject the settlement will not mean an increase to the rider at the present time. Today's order does allow Idaho Power to include $10 million of the $17 million in the rider account be included in this year's Power Cost Adjustment, which the company will file on or about April 15. That $10 million has already been determined by the commission to be prudently incurred expense. In order for conservation programs to be found prudent, they must pass three tests showing that customers pay less for energy than they would if the programs were not in place.

Despite its rejection of the settlement, the commission said it "recognizes and appreciates Idaho Power's commitment in recent years to improve its DSM programs …"

DSM programs reduced peak demand by 290 MW in 2009. That's almost as much reduction as the power that will be generated by the 330-MW Langley Gulch natural gas plant being built near New Plymouth. And energy efficiency programs saved 148,000 MWh in 2009, up from 19,000 MWh in 2004.

"Idaho Power has properly responded to the commission's directive to pursue all cost-effective DSM programs, and the results have been significant and measurable," the commission said.

Case No. IPC-E-10-20, Order No. 32162
January 24, 2011

Proceeds from emission allowances go to Idaho Power customers

About $490,000 of proceeds from Idaho Power Company's sale of surplus emissions allowances will be applied against customers' annual Power Cost Adjustment this spring.

Consistent with prior orders, the company will share 95 percent of the proceeds from the sales with customers and 5 percent with shareholders. The PCA is a yearly adjustment to rates – up or down – to account for the variable costs of power supply not already included in base rates. The inclusion of the emissions proceeds in the PCA will either reduce the size of the increase customers may get with the June 1 adjustment or increase the size of the credit customers may receive.

The commission denied a request by the Idaho Energy Education Project (IEEP) that 8 percent of the proceeds be used to continue funding a two-year pilot project for energy education and efficiency programs in public schools. The commission agreed with findings of the commission staff that more funding directed toward the education project not be approved until the two-year pilot is completed this June. Further, the commission noted, almost $375,000 of the original $500,000 allocated for the project is still available for use.

A 1990 amendment to the Clean Air Act established a national program for reducing acid rain. Sulfur dioxide (SO_2) and nitrogen oxide (NOx) are the primary causes of acid rain. In the United States, about two-thirds of all SO_2 and one-fourth of all NOx comes from thermal (coal and natural gas) electric generating plants. Idaho Power has an ownership interest in three coal-fired plants: Jim Bridger in Wyoming, North Valmy in Nevada and Boardman in Oregon.

Under the federal program, thermal power plant owners are issued limited allowances for their plants' sulfur dioxide emissions based on a specific plant's past emissions and a nationwide cap placed on the total amount of SO_2 that can be emitted. Each allowance authorizes the utility to emit one ton of SO_2. At the end of each year, a utility generating unit must hold allowances equal to its allotted annual SO_2 emissions. A utility that holds over its annual requirement is considered to have surplus allowances that can be sold on the open market or through auctions sponsored by the Environmental Protection Agency.

During 2010, Idaho Power sold 20,000 surplus allowances and reported net sales proceeds of $543,000, after deducting brokerage fees of $5,000.

"By including the SO_2 funds in the PCA mechanism, it will provide an immediate benefit to all customers," the commission said.

Case No. IPC-E-10-46, Order No. 32200
March 9, 2011

PUC approves changes to Idaho Power irrigation program

Some changes proposed by Idaho Power Company to a program that pays irrigators for shutting down pumps during periods of heavy electrical demand have been accepted by state regulators while others were denied.

Idaho Power's Irrigation Peak Rewards Program offers incentive payments to irrigators who volunteer to have their service interrupted during peak-use periods from June 15 to August 15. Volunteer irrigators can have their service interrupted up to a maximum of 60 hours per irrigation season. In exchange, they receive a monthly incentive payment in the form of a bill credit during the three summer months. If not for the program, growing customer demand during the summer months would likely require the construction of natural gas peaker plants.

Idaho Power asked the commission to make a number of changes, chief among those splitting the incentive payments into two portions: a fixed payment (40 percent) and a variable payment (60 percent). The company said the change was needed to better align program costs with the actual need for capacity reduction. Idaho Power doesn't know in advance how many times irrigators will be interrupted, yet the credit is the same regardless of the number of interruptions. During 2010, Idaho Power paid irrigators $11.5 million and interrupted service three times.

The net effect of basing some of the credit (60 percent) on actual interruption would have been to reduce the fixed portion of the credit from $32 per kW to $12.78 per kW, plus another amount paid no more than 60 days after the end of the irrigation season that would be based on actual interruptions.

After taking comments from irrigators, the Idaho Irrigation Pumpers Association, the Idaho Conservation League and commission staff, the commission agreed to a 75/25 split with 25 percent based on actual interruption instead of the company's proposed 60 percent. The result is reduction in the fixed portion of the credit to $25 per kW.

The company's original proposal could cause customers to drop out, reducing the program's effectiveness, the commission said.

The commission denied a request by the company to limit program participation based on the company's need for peak load reduction. The Idaho Irrigation Pumpers Association and commission staff also opposed that change. Commission staff said the company should not only accept participants, but should promote the program in order to achieve peak load reduction over the long term.

Case No. IPC-E-10-27, Order No. 32217
April 1, 2011

Commission rejects conservation funding settlement

A settlement among a number of parties to approve an Idaho Power Company application to shift about $20 million in expenses for conservation programs from the Energy Efficiency Rider currently on customer bills to base rates and to the annual Power Cost Adjustment has been rejected.

The commission said the issues raised in the settlement are more appropriately addressed in a general rate case, which is anticipated to be filed later this year. The commission also expressed concern that shifting some conservation program expense to other areas may result in a cost allocation to some customer classes that is not equitable.

Commission staff and conservation groups supported the settlement, while industrial customers opposed it. The industrial customers said that while shifting conservation program expenses from the 4.75 percent efficiency rider now paid by all customers to other areas may stop further increases in the rider and perhaps reduce the rider amount, customers would end up paying in other ways. The real impact, the industrial customers argued, would be the same as increasing the rider to 6.6 percent.

Parties that supported the settlement included Idaho Power, commission staff, the Idaho Conservation League, the Northwest Energy Coalition, the Snake River Alliance and the Community Action Partnership Association of Idaho, which represents primarily residential customers on lower and fixed incomes. A group representing irrigators did not oppose the settlement, but still did not sign it.

Proponents of the settlement contended that moving some conservation program expenses to base rates and some to the yearly Power Cost Adjustment puts conservation on the same level as acquiring generation from traditional supply-side resources such as coal and natural gas. Including some of that expense in base rates encourages Idaho Power to continue to pursue conservation programs by allowing it to earn a rate of return on some investment, proponents argued.

Idaho Power operates a number of demand-side management (DSM) programs that reduce demand on the company's generation needs during peak times of electrical use. The company also has a number of energy efficiency programs that reduce energy consumption through the use of more energy efficient lighting, appliances and industrial equipment. The cost of the demand-side and energy efficiency programs is recovered from customers through the Energy Efficiency Rider on customer bills, now set at 4.75 percent.

However, the revenue raised from the Energy Efficiency Rider is not keeping up with the cost of demand-side and energy efficiency resources. If changes are not made, the negative balance in the rider account will be $17 million by the end of this year and $30 million by the end of 2012. To pay off that negative balance in one year and continue funding programs at their current level, the rider would have to be increased from the current 4.75 percent to 7.5 percent of customer bills. To recover the balance in two years, the rider would have to be increased to 6.6 percent. The proposed settlement would have reduced the negative balance in the rider account to zero by early to mid-2012 and could result later on in a reduction in the rider.

Commission staff favored the settlement, stating that increasing the rider is "attracting unwarranted attention and criticism," resulting in Idaho Power not getting timely recovery of demand-side costs needed to promote acquisition of cost-effective conservation programs.

Parties proposed that the expense of three major demand-side programs, including one for irrigators and one for residential customers with air conditioners, be shifted to the annual Power Cost Adjustment. They proposed that expenses related to energy efficiency programs for Idaho Power's large commercial and industrial customers be capitalized and included in base rates. Doing so would allow the company to earn a rate of return on demand-side resources just as it does on supply-side resources.

The commission decision to reject the settlement will not mean an increase to the rider at the present time. Today's order does allow Idaho Power to include $10 million of the $17 million in the rider account be included in this year's Power Cost Adjustment, which the company will file on or about April 15. That $10 million has already been determined by the commission to be prudently incurred expense. In order for conservation programs to be found prudent, they must pass three tests showing that customers pay less for energy than they would if the programs were not in place.

Despite its rejection of the settlement, the commission said it “recognizes and appreciates Idaho Power’s commitment in recent years to improve its DSM programs …”

DSM programs reduced peak demand by 290 MW in 2009. That’s almost as much reduction as the power that will be generated by the 330-MW Langley Gulch natural gas plant being built near New Plymouth. And energy efficiency programs saved 148,000 MWh in 2009, up from 19,000 MWh in 2004.

“Idaho Power has properly responded to the commission’s directive to pursue all cost-effective DSM programs, and the results have been significant and measurable,” the commission said.

Case No. IPC-E-11-04, Order No. 32248
May 19, 2011

Idaho Power rates to increase slightly due to pension expense

State regulators are allowing Idaho Power Company to increase rates by an average 1.39 percent to recover the company’s cash contribution to its defined benefit pension plan. The increase will be effective June 1, the same effective date for two other rate adjustments that will likely result in an overall decrease in rates.

Idaho Power sought commission authority to increase its contribution to its pension plan from $5.4 million annually to $17.1 million annually over three years in order to recover a $60 million contribution Idaho Power made to its defined benefit pension plan. The company had to make a contribution to its plan to satisfy requirements of the federal Employee Retirement Security Act (ERISA).

While allowing the expense recovery, the commission continued to urge the company to consider modifying its plan to one that would require shareholders and employees to participate in a greater share of costs. “The commission remains concerned that Idaho Power’s defined benefits pension plan places the burden solely on customers to pay all increased costs of the plan,” the commission said. The commission, in a separate order, directed the Idaho Power to annually review the company’s total employee compensation and benefits package and compare it with those offered by other utilities.

The company had the option, under ERISA, to contribute a minimum requirement of $5.8 million, but making the larger contribution now saves the company and ratepayers about $11 million. In addition, the large contribution now will result in another $1 million savings to the variable portion of the company's premiums.

Idaho Power's contributions to its pension plan have always been included in base rates. However, since 2003 the company was not required to contribute to the plan because the market value of the plan's assets was more than enough to cover future obligations. Recent market conditions and increasing pension obligations require Idaho Power to start funding the plan again.

Case No. IPC-E-11-22, Order No. 32424
December 28, 2011

Commission extends Idaho Power revenue sharing agreement

The commission approved an Idaho Power Company application that allows the company to continue to accelerate tax benefits to bolster earnings and share a portion of those earnings with customers.

Idaho Power receives income tax benefits based on the level of plant investment in previous years. The accumulated deferred investment tax credits are typically spread over the book life of the associated plant investment and used to reduce income tax expense included in customer rates during that period. However, as part of the 2010-11 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 at $15 million a year for three years if its return on equity (ROE) falls below 9.5 percent. The settlement further stated that Idaho Power would split 50-50 with customers the portion of earnings 10.5 percent or greater. The customer benefit would be in the form of rate reductions or an offset to amounts that would otherwise be included in customer rates.

Up until the 2010 agreement, Idaho Power had not been able to earn its authorized rate of return for the previous decade in both its Idaho and Oregon jurisdictions. While the exact amount of the 2011 year-end ROE isn't known yet, it is above 10.5 percent, creating the sharing opportunity. Without the one-time tax benefits received in 2011, the 2011 ROE was anticipated to be below 9.5 percent.

The agreement is a modification of the 2010 settlement that extends the ability of Idaho Power to amortize the credit through Dec. 31, 2014 and make an adjustment to the sharing portion for 2011. That adjustment provides an additional benefit to customers for earnings above 10.5 percent. Seventy-five percent of the company's share of earnings above 10.5 percent will be used to offset company pension expenses that would otherwise be included in customer rates. That same provision would be included in the 2012-2014 extension of the agreement. During

2012-2014, if ROE is between 10 and 10.5 percent, the customers' 50-50 share will be a reduction applied at the same time as the annual Power Cost Adjustment (PCA) every June 1.

"The existing accounting order approved by the commission has benefitted customers, the company and shareholders," the commission said. "Rating agencies and shareholders generally view the earnings stability provided by the past agreement as positive."

The agreement will provide customers an estimated $15 million benefit they would not receive and it reduces amounts that would otherwise be included in customer rates, the commission said.

In addition to commission staff and the company, parties participating in the settlement discussions were the Industrial Customers of Idaho Power and Micron Technology, Inc.

Case No. PAC-E-10-07, Order No. 32196
March 1, 2011

Commission issues final order in Rocky Mountain Power rate case

The commission released its final order in a Rocky Mountain Power (RMP) rate case that began in May 2010. In late December, the commission issued an interim order that established new rates for all customer classes that became effective Jan. 1, 2011, but still had issues to resolve regarding the utility's largest customer, the Monsanto Company plant in Soda Springs.

The 68-page order addresses the Monsanto issues and provides the findings to support the late December decision to grant the company an overall 6.78 percent increase in its annual revenue requirement, or $13.75 million. When the company filed its application last May, it asked for a 13.7 percent increase, or $27.7 million. After technical hearings, the company lowered its request to 12.3 percent or $24.9 million.

The 6.78 percent average increase is offset by a decision to reduce customers' Energy Efficiency Charge from 4.72 percent to 3.4 percent, resulting in a net average increase for residential customers of about 5.5 percent. The net amount of actual increase varies by class of customer and by usage. For example, with the new two-tiered rate design approved by the commission in this case, a residential customer using RMP's average consumption of 839 kilowatt-hours per month will realize a 1.5 percent decrease. The two-tiered rate structure increases rates as consumption increases, with residents paying more after the first 700 kWhs of use in the summer and after the first 1,000 kWh in the winter. The rates for the first tier are actually lower than the company's previous rates.

From May to October, standard residential customers will pay 9.58 cents per kWh for their first 700 kWhs. The former May-October rate was 10.4 cents. For use exceeding 700 kWhs during summer, the new rate is 12.9 cents.

During the winter season (November through April) residential customers will pay 7.33 cents per kWh for the first 1,000 kWhs. The former winter rate was 8 cents. For use above 1,000 kWhs, the rate is 9.9 cents.

Part of the average 6.8 percent annual increase in rates is a customer service charge that varies according to customer class and is added to cover metering and billing expense. For most residential customers that charge is $5. The company requested $12.

Many of the customer comments opposed RMP's proposal to increase the standard residential rate by 8 percent, while residential customers who are on the company's Time of Day program would pay 15.6 percent more. The commission determined to assign an equal percentage increase for both residential customers of 6.78 percent.

The largest reductions the commission made in RMP's request (addressed in detail later in this press release) include 1) allocating $11.4 million in expense for the company's irrigation load control program to the utility's entire six-state system and not just to Idaho customers; 2) reducing RMP's requested allowable rate of return from 8.36 percent to 7.98 percent and its requested Return on Equity from 10.6 percent to 9.9 percent; 3) allowing only 73 percent of the company's investment in the Populus to Terminal (Downey to Salt Lake City) transmission line and putting the remaining 27 percent in plant held for future use; and 4) disallowing in rates all wage increases awarded by the company to employees during 2009 and 2010 as well money for the company's Supplemental Executive Retirement Plan. Removing wage increases does not necessarily mean employee increases will be withdrawn, but that the cost would not be paid by customers.

"In making these adjustments we address concerns raised by parties and customers and acknowledge the economic conditions and service requirements in the company's southeastern Idaho service territory," the commission said. The commission conducted two workshops, four public hearings, two technical hearings and a telephonic hearing. Nearly 100 people testified and the commission also received more than 200 written comments.

Regarding RMP's request for an increased rate of return and return on equity, the commission order states:

> *"We find that RMP (Rocky Mountain Power) in this case downplayed the poor economic conditions that exist in its Idaho service territory where many are on fixed incomes, unemployed and underemployed. This commission cannot discount as simply anecdotal the testimony and comments of RMP customers. While we cannot say 'no' to a requested increase in rates because customers are uniform in their opposition, together their testimony serves as the real-life context and backdrop of our decision. Their testimonies and comments remind us that we are not*

engaged in simply an academic exercise dealing in regulatory principles, generalities and industry averages. Our decision has real consequences."

However, the commission said it also has statutory obligations to balance the interests of both customers and company to ensure a financially healthy utility that can provide reliable service and plan for future needs:

"We recognize that for some customers any increase may result in economic hardship. That being said, we have a dual obligation in rate cases. To customers our task is to establish rates that are fair and reasonable. To the company we have a statutory obligation to set rates at a level sufficient to allow RMP to recover its reasonable expenses of operation and receive a reasonable return on prudent capital investments in utility plant and facilities. Carrying out this duty is necessary for the company to be financially sound and capable of providing its customers with safe and reliable electric service."

When the commission denies cost recovery to a utility, it must be able to legally demonstrate why the utility's costs were not prudently incurred or in the best interest of customers. All commission decisions can be appealed to the state Supreme Court.

Rocky Mountain Power is a division of PacifiCorp, which operates in six states and is in the midst of a multi-year program of investing in renewable energy, transmission facilities and environmental controls to serve the growing demands of its customers in Idaho and across its system. The company claimed that its system-wide expenses during 2009 include over $4 billion of new plant investment and $87 million in increased power costs. Those expenses are then allocated among the six states based on each state's electrical load, which for Idaho is about 6 percent of PacifiCorp's total system load. <u>Expenses that cannot be demonstrated to benefit Idaho customers are not included in the rates Idaho customers pay.</u>

The case was extended for an additional technical hearing to consider changes to Monsanto Company's agreement with Rocky Mountain Power that allows the utility, under specified circumstances, to curtail its power delivery to Monsanto to meet other customer needs. Monsanto has a total load of 182 megawatts, but up to 173 MW can fall under the interruptible portion of the agreement. The interruptibility provisions of the agreement are significant because electric rates are a substantial portion of production costs at the elemental phosphorous plant and also because Monsanto's economic vitality has a large impact on the economy of Soda Springs and the surrounding area.

The electric service agreement between Monsanto and RMP allows the utility to curtail electric delivery to Monsanto under any of these three circumstances: 1) to allow the utility to meet mandated reserve requirements, 2) for economic reasons – as when market prices for electricity allow RMP to save money for itself and its customers – and 3) to interrupt for system integrity to avoid outages. The agreement limits the number of megawatts that can be curtailed and the number of hours that curtailment can happen for each of the three circumstances.

RMP proposed significant reductions in the amount it said it would pay Monsanto for the interruptions. Monsanto disputed the value the company placed on the interruption services. In today's order, the commission established values for each of the three interruptibility products that are higher than those proposed by RMP but less than those proposed by Monsanto. The actual numerical values are proprietary. The commission also encouraged the parties to craft an agreement that establishes the value of the products for five years rather than three years. The commission said the longer agreement would promote greater price certainty for Monsanto as well as allow RMP to plan more effectively into the future.

The commission's order also directs RMP to increase its annual funding for low-income weatherization in Idaho from $150,000 to $300,000 and to increase the dollar amount of RMP funds available for each weatherization project from 75 percent to 85 percent of total eligible costs. The commission noted there is a five-year backlog of homes that need and are eligible for weatherization in southeastern Idaho.

Below is a more detailed summary of the commission's finding on some of the major issues in this case:

Irrigation load control program costs

The Idaho Irrigation Load Control program pays credits to irrigation customers who agree to have their service curtailed during times of peak demand. In 2007, the program provided 78 megawatts to the company, but by 2009 that had grown 250 percent to provide 276 megawatts of demand reduction for the company. The nearly $20 million in savings benefits PacifiCorp customers in all six states and, therefore, the $11.4 million cost of the program should be allocated system-wide and not just to Idaho customers, the commission ruled. Doing that removes $3.25 million in Idaho annual revenue requirement for RMP and also allows a reduction to the Energy Services Rider paid by customers from 4.72 percent to 3.4 percent.

"We find that it is unreasonable to expect Idaho customers to continue to bear the costs associated with the current jurisdictional treatment of the Irrigation Load Control Program expenses," the commission said.

Rate of return, return on equity

The rate of return is the amount the company is allowed the opportunity to earn on its capital investment. The company requested 8.357 percent and was granted 7.98 percent. The return on equity is the rate of return equity investors expect given the risks of an individual security and consistent with returns that are available from similar investments. The company requested 10.6 percent and was granted 9.9 percent. Setting the allowable rate of return and return on equity is not a guarantee the company will reach those levels, but caps the returns at the commission's authorized level.

The commission uses three primary standards in determining rate of return. The authorized return should be 1) sufficient to maintain financial integrity, 2) attract capital under reasonable terms and 3) be commensurate with returns investors could earn by investing in other enterprise of comparable risk. The rate of return must be enough to attract capital investment in new transmission, distribution and generation but not so high as to be unreasonable for customers.

The commission cited current economic conditions in southeastern Idaho as a primary factor in reducing the company's requested return on equity to 9.9 percent.

Populus to Terminal Transmission Line

The line, which runs from Downey to Salt Lake City, is the first of eight proposed new high-voltage transmission segments that will make up PacifiCorp's Energy Gateway transmission expansion project. The line benefits Idaho customers in that it is intended to add 1,400 MW of transmission capacity to an already heavily constrained area and allows the company access to less costly generation sources.

However, the commission ruled that because the company can use only about 1,040 MW of the total capacity, Idaho's portion of the full cost should not be included in rates until the entire 1,400 MW is available to customers. Therefore, the commission placed 27 percent of the transmission investment into Plant Held for Future Use. "Idaho, we find, will pay its fair share to meet the company's system load and transmission requirements but we will not allow full ratebasing of investment in Populus to Terminal prematurely and we will not require Idaho customers to assume and pay for unused capacity."

Wages and pensions

Wage increases awarded employees in 2009 and 2010 cannot be included in rates, reducing revenue requirement by almost $1 million. The commission's order states:

> *"The Commission finds that in tough economic times the local economy in the Company's service area is a greater indicator as to the appropriateness of a wage increase than market data and industry averages. We find no demonstration by the Company that the union and non-union wage increases were required for the Company to be a competitive employer able to retain or attract employees. We find no offer of proof that without the union and non-union wage increase the service provided by the Company would be degraded and safety compromised. We find that as a certificated provider of service RMP has elected to be a member of the communities it serves."*

The commission also disallowed recovery of costs related to RMP's Supplemental Executive Retirement Plan. "The company has not demonstrated that these costs are related to providing services to southeast Idaho," the commission said. "The responsibility for generous severance benefits for executives, we find, is the responsibility of the company and its shareholders, not Idaho customers."

Intervenors in the case who provided testimony and rebuttal and cross-examined witnesses during technical hearings included Monsanto Company, the Idaho Irrigation Pumpers Association, the Idaho Conservation League, PacifiCorp Idaho Industrial Customers, the Community Action Partnership Association of Idaho and commission staff.

Case No. PAC-E-11-07, Order No. 32216
March 31, 2011

Yearly adjustment results in 5.8 percent increase in RMP surcharge

A one-year surcharge on the bills of Rocky Mountain Power customers will be set at an average 5.8 percent. The average increase to standard residential customers is 5.2 percent.

Rocky Mountain Power originally sought an average 7.4 percent surcharge to pay off a deferral account that had accumulated to $12.8 million. The commission approved a recovery of $10.4 million, electing to postpone recovery of about $2.4 million until next year.

The surcharge, which is effective April 1 and expires next March 31, allows Rocky Mountain Power to pay off deferred power supply costs that vary from year to year and are not included in base rates. These include expenses that change from day to day such as those for coal, natural gas and electricity from the wholesale market. **None of the money collected in the surcharge can be used to increase company earnings, but goes directly toward paying off deferred and unanticipated power supply expense.** During years that market prices for power supply are less than what is included in base rates, customers would receive a one-year credit. To encourage the company to be prudent in its power supply purchase decisions, the commission requires that shareholders pay 10 percent of the power supply expenses not already included in rates.

The surcharge is called an Energy Cost Adjustment Mechanism, or ECAM. The surcharge or credit will be made April 1 of every year. The commission instituted the mechanism in 2009 as a way to more closely match customer rates with the actual cost of providing service. Doing so reduces the frequency and size of general rate case filings. It also helps to keep financing costs, which are ultimately paid by customers, at lower levels.

That $2.4 million the commission elected to postpone to next year is about one-half of a load-growth adjustment rate that makes up part of the ECAM. Because the commission recently modified the portion of the ECAM that accounts for increases or declines in load growth, it anticipates a lower load growth adjustment next year which should contribute to a less of an increase in the overall ECAM next year. Further, the commission said, spreading some of the ECAM deferral over two years helps to mitigate the impact of a rate increase customers received just three months ago.

Case No. PAC-E-10-07, Order No. 32224
April 19, 2011

Commission denies most of Rocky Mountain Power petition

The commission denied nearly all Rocky Mountain Power's petition that it reconsider the decision it made Feb. 28 to grant it an average 6.8 percent rate increase. The commission did grant a small portion of Rocky Mountain's petition which increases average base rates by just under three-tenths of 1 percent, from 6.8 percent to 7.07 percent. The approximate 0.3 percent adjustment will be applied to rates April 25. When Rocky Mountain Power originally filed its request last May, it sought a 13.7 percent increase, but later adjusted its request to 12.3 percent.

The commission denied Rocky Mountain Power reconsideration on its earlier decisions to:

- Place 27 percent of the cost for the new Populus to Terminal transmission line in eastern Idaho in an account called Plant Held for Future Use;
- Not allow carrying charges on that 27 percent;
- Not allow wage increases incurred during 2009;
- Establish a rate of return of 9.9 percent rather than the 10.6 percent sought by the company.

The commission granted reconsideration in the following areas:

- Allow $95,597 of the total $993,515 disallowed in wage and salary increases. The $95,597 allowed is a portion of 2008 annualized labor expense;
- Allow $1.082 million to be included of the total $34.2 million denied for wind integration expense due to a calculation error.

Other minor adjustments, including those above, resulted in a new annual revenue requirement of $14.35 million. The revenue requirement previously approved by the commission was $13.75 million. The company originally requested $27.7 million.

The commission also clarified its intent regarding the value of the credits awarded Monsanto Company for agreeing to have its electrical service interrupted during peak load times. The commission said the value of the credits can be changed when the company's overall demand and energy charges change as the result of a rate case and that the credit applies only to 162 MW of Monsanto's billing demand and not on the entire load.

The commission decided to address later the question of whether an order that directs Rocky Mountain Power to commit $50,000 for low-income conservation education is a one-time commitment or an annual expense. The commission said the issue can be taken up in the company's next general rate case which is expected to be filed in late May.

Regarding its overall decision in this case, the commission said it "strongly disagrees" with Rocky Mountain's assertion that the commission based its decision on public perception and allowed the ratemaking proceeding to become a political referendum. The commission said its decision was based on evidence in the record presented at hearings.

Rocky Mountain Power claims the new Populus transmission line that begins near Downey and extends into the Salt Lake City area benefits customers even if it not yet entirely utilized because it increases system reliability and transfer capability. It also allows the company to use the line to import lower-cost market energy and to sell excess energy off system, Rocky Mountain claims. Rocky Mountain asked that if the entire cost of the line isn't included in customer rates that it be allowed a carrying charge on the portion placed in Plant Held for Future Use.

The commission denied both requests, noting that state statute (Idaho Code § 61-502A) prohibits the commission from granting utilities a rate of return on Property Held for Future Use that is not used and useful in providing service to customers. "This statute is clear and unambiguous," the commission said.

"Contrary to the company's argument, the commission has not denied recovery of a full portion of the investment made in the transmission line," the commission said. "Recovery has simply been deferred until such time as the transmission line is fully utilized and available to the benefit of Idaho ratepayers." The commission did, however, clarify that no depreciation of the investment will occur on the portion of transmission expense held for future use.

Regarding pay increases, Rocky Mountain Power argued that the state of Idaho awarded its employees a 3 percent increase in 2009, citing that as evidence that the company's base wage increases were reasonable. Commission staff asserted that only 3 percent of all state employees received increases during 2009 and that Gov. Butch Otter ordered state agencies to reduce payroll costs by 5 percent during that year. "The commission finds that Rocky Mountain Power has failed to present any evidence which would compel us to revisit the issue of wage increases. Instead, the company has made spurious and false assertions regarding alleged wage increases received by state of Idaho employees during 2009," the commission said.

The company argued that just as expense to integrate wind into its transmission expense ($6.50 per megawatt-hour) is allowed for PURPA projects, it should also be allowed for company-owned wind plants. The commission said Rocky Mountain failed to adequately prove its actual wind integration expense. The $6.50 per MWh allowed for non-company owned wind projects does not mean the expense is the same for company-owned projects, the commission said.

Rocky Mountain also asserted that the 9.9 percent return on equity (ROE) allowed by the commission is erroneous because it invents a new standard of "poor economic conditions." The commission disagreed, stating the ROE is based on "expert testimony and exhibits available in the case record." The U.S. and state constitutions grant the commission a "broad range of reasonableness" in establishing rates of return, the commission said, noting that the 9.9 percent ROE was within the range proposed by staff and Monsanto.

Case No. PAC-E-11-06, Order No. 32235
May 3, 2011

Parties settle on changes to irrigation load control program

The commission accepted a settlement proposed by Rocky Mountain Power, eastern Idaho irrigators and commission staff that will result in less drastic changes to the company's irrigation load control program than those originally proposed by the company.

Rocky Mountain Power's Dispatchable Irrigation Load Control program, in place since 2007, allows the utility, during periods of peak demand, to turn off the pumps of irrigators who volunteer to participate. In exchange, irrigators received a credit of $30 per kilowatt. Pumps can be turned off for periods of time during June through August from 11 a.m. to 7 p.m. as long as the utility provides prior-day notification and as long as total curtailment for any participant does not exceed 52 hours.

On Jan. 20, Rocky Power filed an application to change the program because of voltage problems created by rapidly expanding participation in the program. When the program began in 2007, participating load totaled 65 megawatts, but that increased to 278 MW in 2010. The company claimed that much curtailment was creating voltage control problems with circuits at four substations experiencing unacceptable increases. To respond, Rocky Mountain wanted to reject prospective program participants and reduce the credit irrigators receive from $30 per kW to $25.30. The company also proposed to modify the penalty irrigators receive for opting out of scheduled curtailments.

Irrigation customers as well as commission staff objected to some of the proposed changes. A negotiated settlement by commission staff, the Idaho Irrigation Pumpers Association and the company will allow the utility to limit program participation to 232 MW for the next two years, or an 18 percent reduction. Further, the $30 per kW credit to each irrigator will be reduced by $1.45 for this season only to account for 11 MW of unobtainable curtailment due to the voltage issues at four substations. In the meantime, the company agreed to invest a minimum of $1.3 million in capital improvements to install equipment needed to address the issues at the four substations before the start of the 2012 irrigation season.

During the two-year period of this settlement, new participants or additional load reduction from existing participants will not be accepted. Volunteer irrigators can decline to participate in some of the curtailments, but the credit they are paid by the company is reduced for each curtailment incident for which the irrigator decides to opt out.

The Idaho Conservation League also participated in the settlement discussions. It did not sign the settlement but does not oppose it.

Case Nos. AVU-E-11-01, Order No. 32371
September 30, 2011

Rate case settlement results in decrease to customers

The commission granted Avista Utilities a base rate electric increase of about 1.1 percent and a base rate gas increase of 1.6 percent. However, due to decreases in other rate components, billed rates for customers actually decreased effective Oct. 1.

The overall rate decrease to electric customers is an average 2.4 percent for all customer classes (2.1 percent to residential class) and an average 0.8 percent to gas customers (0.5 percent to residential class).

While permanent base electric rates increase, the annual Power Cost Adjustment – which varies every year depending on water and market conditions – is a decrease of about 6 percent. Ratepayers also benefit from an increase in a credit given residential and small-farm customers from the Bonneville Power Administration.

On the gas side, customers are getting an increase to both base rates and the annual Purchased Gas Cost Adjustment, but they are getting a more substantial decrease due to the reduction in an efficiency rider used to fund to conservation programs.

An electric residential customer using the company's average of 956 kilowatt-hours a month will see a $1.79 per month decrease for a revised monthly bill of $82.02. The overall electric rate decreases from the current 7.9 cents per kWh for the first 600 kWhs of use to 7.68 cents per kWh. For use above 600 kWh, the billed rate decreases from the current 8.8 cents 8.6 cents per kWh.

A residential natural gas customer using an average of 62 therms would see a 20-cent per month decrease for a revised monthly bill of $60.96. The billed rate decreases from the current 91.5 cents per therm to 90.7 cents per therm.

Part of the base electric and gas rate increase include an increase in the monthly customer service charge from $5 to $5.25 per month for electric customers and from $4 to $4.25 per month for natural gas customers.

In the base rate electric case, Avista is granted a $2.8 million increase in annual revenue. When Avista filed the case in July it asked for a $9 million increase in annual revenue. Avista sought a $1.9 million increase in gas revenue and is granted $1.1 million.

The commission approved a negotiated settlement between the utility, commission staff and other parties representing industrial customers, the Idaho Conservation League and the Community Action Partnership Association of Idaho, the latter representing primarily customers on low- and fixed-incomes.

A key part of the settlement is that Avista agrees to not collect another base electric or gas rate increase before April 1, 2013. (This does not include yearly tracker adjustments such as the Power Cost Adjustment or Purchased Gas Cost Adjustment and energy efficiency rider adjustments.)

The commission said it appreciated the "diligent work" by all the parties to resolve the issues in the case. "We note that the stipulation and settlement represents a significant reduction in the requested revenue increase," the commission said. The company was granted only 31 percent of its original electric rate increase request and 58 percent of its original gas increase request. Further, the commission said, the provision in the settlement to not implement new base rates before April 1, 2013 "provides an extended period of rate stability that otherwise might not occur."

The agreement also provides an additional $10,000 in funding for outreach to low-income customers on conservation measures, bringing the total annual funding for that program to $50,000. This is in addition to the $700,000 already made available for low-income weatherization projects.

The parties to the settlement are also directed to participate in workshops to address updating the cost of service to each customer class, rate design and low-income programs.

ELECTRIC ADJUSTMENTS include two increases and two decreases, for a net overall rate decrease of 2.4 percent.

Base rate increase of $2.8 million, or an average 1.1 percent. (Case No. AVU-E-11-01)

Deferred state income tax increase of $8.7 million. This was previously approved as part of the settlement of the 2010 rate case. Deferred state income tax benefits are no longer available to reduce rates. (Case No. AVU-E-10-01, Order No. 32070)

Power Cost Adjustment (PCA) decrease of $15.5 million or about 6 percent. The PCA is a yearly adjustment to rates based on the always changing costs of power supply. When water is plentiful and market prices for power lower than anticipated, customers typically get a credit. During low-water years or during years of high market and fuel costs, customers typically get a surcharge. Avista's PCA, which is adjusted every Oct. 1, this year is a $15.5 million decrease. (Case No. AVU-E-11-03, Order No. 32375)

A decrease in customer bills as the result of a $2.2 million increase in the Bonneville Power Administration (BPA) exchange credit given residential and small-farm customers. The BPA is a not-for-profit federal agency that markets power from 31 federal hydroelectric dams and a nuclear plant in the Northwest. The 1980 Northwest Power Act required that residential and small-farm customers in the Northwest share in the benefits of the federal hydroelectric projects located in the region. Avista applies the benefits it receives, which usually fluctuate annually, to customers as a credit on their monthly electric bill.

The battle over wind

Dating as far back as 2005, Idaho's utilities, the Commission and renewable energy developers have been trying to determine the most equitable method to price renewable energy, particularly wind. Wind development, particularly under federal PURPA provisions, has been rapid in Idaho Power's service territory in particular.

Up until the filing of this report, the issue of a true avoided-cost and an appropriate surrogate avoided resource were still being debated. Technical hearings are scheduled for August 7-9, 2012, in the GNR-E-11-03 docket to address these issues. Here is a timeline of the issues as they have evolved.

June 2005 – Idaho Power Company files application to be granted a six- to nine-month suspension from its obligation under the federal Public Utility Regulatory Policies Act (PURPA) to buy energy generated by qualifying wind-powered projects. Later, Idaho's two other major regulated utilities, Avista Utilities and PacifiCorp (then Utah Power) joined the case, seeking to be included in the moratorium. The utilities sought the moratorium to address the growing number of intermittent wind proposals, which, they claimed, could impact the reliability of the transmission grid. An Idaho Power analysis concluded that in order to safely integrate 1,000 MW of intermittent wind generation, it would be necessary to concurrently add 640 MW of combustion turbines to provide capacity when wind resources were not operating. Between November 2004 and its June 2005 filing, Idaho Power has signed contracts from wind developers totaling 61.5 MW and has applications pending before the commission for another 21.5 MW. The company has also received contracts from developers intending to pursue another 193 MW of wind projects. Before 2004, Idaho Power had less than 1 MW of PURPA wind-powered generation under contract.

August 2005 – Rather than granting the suspension, the commission (Order No. 29839)* reduced the size of non-firmed wind projects that can qualify for the commission's published rate from 10 megawatts to 100 kilowatts while the commission examined the case further. The commission said it needed more time to study the impact of the wind projects on reliability for customers and to examine whether the higher price paid for PURPA wind projects is beneficial for customers who end up paying the cost of higher-priced energy. (The money Idaho Power pays wind developers is included as part of Idaho Power's overall power supply cost that is eventually passed on to customers in the company's power cost adjustment process every spring.)

February 2007 -- Idaho Power proposes that the 100-kilowatt limit on wind projects that can qualify for published rates be moved back up to 10,000 kilowatts or 10 megawatts. Idaho Power completed a wind integration study and asked the commission for a return to the 10 MW size cap if wind developers: 1) agree to share in the cost of state-of-the-art wind forecasting services; 2) include a guarantee in future wind contracts that demonstrates projects are mechanically capable to generate at full output during 85 percent of the hours during a month and 3) agree to accept a discount of $10.72 per MW for wind integration. Idaho Power would also agree to remove the "90/110 performance band" that stipulated when output was less than 90 percent of projections or more than 110 percent of projections, Idaho Power could pay developers a lesser market-based rate rather than the PURPA rate.

July 2007 – Avista Utilities and PacifiCorp also file cases proposing return to 10 MW limit with conditions as proposed by Idaho Power.

Press release:
http://www.puc2.idaho.gov/intranet/cases/elec/IPC/IPCE0703/staff/20070223PRESS%20RELEASE.HTM

August 2007 -- Commission staff conducted two workshops to explore whether the utilities and wind developers could agree to a generic wind integration adjustment, but the parties were unable to settle. With the parties unable to agree, the matter was put before the commission for a decision.

http://www.puc2.idaho.gov/intranet/cases/elec/IPC/IPCE0703/staff/20070822PRESS%20RELEASE.HTM

February 2008 – After nearly three years, three cases involving how much it costs to add wind to utilities' transmission grids is resolved. Three orders establish the amount of discounts utilities can assess against wind developers to account for the cost of integrating wind into their systems. The orders also removed the 100 kW cap on the size of small-power projects that can qualify for the published rate, bringing it back to 10 MW. Also removed was the 90-110 performance band that allowed utilities to pay wind developers a market rate rather than the typically higher state rate when wind output from projects did not fall within forecasted ranges. The order established a tiered-discount for Idaho Power and Avista that increased as more wind is added, but caps the discount so that it can go no higher than $6.50 per MWh. For the first 300 megawatts of wind on a utility's system, the discount is 7 percent. That increases to 8 percent when a utility has contracts for 301 to 500 MW of wind and to 9 percent for 501 MW or more. The commission approved a flat discount rate of $5.10 for PacifiCorp, which operates as Rocky Mountain Power in southeastern Idaho.
http://www.puc2.idaho.gov/intranet/cases/elec/IPC/IPCE0703/staff/20080221PRESS%20RELEASE.HTM

November 2010 – Idaho Power, Avista and PacifiCorp (now Rocky Mountain Power in eastern Idaho) file a joint petition asking the commission to investigate a number of issues related to small-power projects that qualify for published rates. The utilities asked that the eligibility cap on the size of projects that qualify for the posted rate be reduced from 10 average megawatts to 100 kilowatts in 14 days. The utilities contend a rapidly expanding number of wind projects are having a profound price impact on customers and on transmission systems. The utilities claim that the small-power projects PURPA was originally intended to encourage are now developed by sophisticated large-scale wind farms that aggregate several projects to fall under the 10 MW limit within a mile apart from each other to qualify for the avoided-cost rate. When combined, these projects can total up to 100 or 150 MW interconnecting at one delivery point. Idaho Power claimed it had 208 MW of wind generation and another 264 MW of approved wind contracts scheduled to be online by the end of 2010. Idaho Power said it could have 1,100 MW of wind generation on its system in the near term, which exceeds the amount of power used in Idaho Power's total system on the lightest energy-use days.

The commission denied the request to lower the size limits of projects than can qualify for the posted rate. However, the commission did say that any decision it makes in regard to lowering the limit would become effective Dec. 14, 2010.

http://www.puc2.idaho.gov/intranet/cases/elec/GNR/GNRE1004/staff/20101206PRESS%20RELEASE.HTM

February 2011: Commission issues order reducing the eligibility cap for wind and solar projects to qualify for published rates from 10 MW to 100 kW. The 10 MW limit remained for non-wind and non-solar renewable projects. The commission said the smaller size limit for wind and solar projects is temporary until a number of issues that led to a petition filed by the state's largest three electric utilities can be resolved. Wind and solar projects that signed agreements with utilities dated before Dec. 14 are still under the former 10 MW eligibility cap.

http://www.puc2.idaho.gov/intranet/cases/elec/GNR/GNRE1004/staff/20110207PRESS%20RELEASE.HTM

February and March 2011: With the commission's case still pending, the Idaho Legislature gets involved when residents in eastern Idaho, angry over wind development, from Idahoans for Responsible Wind Energy and lead the charge to declare a two-moratorium on wind development. There is also significant opposition to the extension of a sales tax rebate on equipment used in producing renewable generation. The tax was scheduled to sunset by June 30 without legislative action to extend it. The moratorium on wind development was killed in committee on an 11-8 vote.

http://www.businessweek.com/ap/financialnews/D9M4F3000.htm

The debate over whether to extend the sales tax rebate continued to the final day of the session. A compromise bill to extend the tax credit for just another four months failed on an 18-17 State Senate vote, the final vote of the legislative session.

http://www.idahoreporter.com/2011/idaho-senate-rejects-wind-energy-tax-rebate-extension/

Wind development was one of the major issues of the session, if not the major issue. Wrote John Miller of Associated Press: "*What to do about wind power in Idaho has become one of the most expensive issues in the Legislature this year, judging from more than a dozen lobbyists employed by the utilities, wind energy developers and foes of the industry ...*"

June 2011: The commission issues an order leaving the eligibility cap under which wind and solar projects can qualify for commission published rates at 100 kilowatts. As a result, developers of 12 Idaho Power Company wind projects and five Rocky Mountain Power projects whose contracts were executed after the Dec. 14 deadline will not be eligible for published rates. However, the wind projects could still be developed under a rate negotiated between the project developers and the utilities. Ten Idaho Power wind projects that were submitted just before the deadline have already been approved by the commission.

Commission staff and other parties attempted to establish criteria that would allow the commission more discretion in determining whether a QF was truly a small project as anticipated by PURPA or a larger project that had disaggregated. The commission declined to adopt the criteria, maintaining that the potential would still remain for the criteria to be circumvented.

The commission said it will initiate another proceeding to investigate the methodology used to calculate the avoided-cost rate. "We believe it is more appropriate to first establish the just and reasonable avoided-cost rates before we implement procedures for obtaining the rate," the commission said. "While we recognize the impact that this decision will have on small wind and solar projects, it would be erroneous, and illegal pursuant to PURPA, for this commission to allow large projects to obtain a rate that is not an accurate reflection of the utility's avoided cost for the purchase of QF generation," the commission said.

The Northwest and Intermountain Power Producers Coalition argued that the 10 average MW cap has worked "remarkably well" for Idaho. "We fundamentally think that it is unfortunate that the three utilities initiated this docket at all," NIPPC said. "We believe that this docket has been an unnecessary exercise and that is because the system is not broken and, hence, it does not need to be fixed."

http://www.puc2.idaho.gov/intranet/cases/elec/PAC/PACE1101/staff/20110608PRESS%20RELEASE.HTM

July 2011: The Commission declines petitions from wind developers to reconsider their June order. Five Rocky Mountain Power projects and two Idaho Power projects appeal to the State Supreme Court.

http://www.puc2.idaho.gov/intranet/cases/elec/PAC/PACE1101/staff/20110727PRESS%20RELEASE.HTM

August 2011: The Cedar Creek projects file a petition to the Federal Energy Regulatory Commission, asking it to "institute an enforcement action" against the commission for violation of PURPA. Cedar Creek alleged that QFs are entitled to receive avoided cost rates on the date a legally enforceable obligation is incurred, not solely the date on which a contract is signed by both parties and fully executed. Cedar Creek alleged that legally enforceable obligation occurred well before the commission's Dec. 14, 2010, deadline.

http://www.puc2.idaho.gov/intranet/cases/elec/FER/FERE1102/general/20110810NOTICE%20OF%20PETITION%20FOR%20ENFORCEMENT.PDF

October 2011: FERC issues an order declining to institute an enforcement action but said the PUC's June order was "inconsistent with our regulations implementing PURPA." It said Cedar Creek may pursue its arguments in the appropriate court. The commission responds the same month by announcing it will schedule four settlement discussions with Cedar Creek developers.

November 2011: The Commission issues an order announcing the scheduling for a new docket, GNR-E-11-03, to review the terms of PURPA power purchase agreements including, but not limited to, the surrogate avoided resource and Integrated Resource Planning methodologies for calculating avoided cost rates. After the ***18*** parties to the case pre-file direct testimony by Jan. 31, 2012, a settlement conference will be held Feb. 28. Rebuttal testimony will be filed by the end of June with hopes that the case will conclude by the end of July.

December 2011: Sales agreements between PacifiCorp and three of five wind projects rejected earlier by the commission are approved, but the projects may be moved from their original Bingham County location to a new site -- Ridgeline Energy's Meadow Creek wind farm in Bonneville County.

Because of already available transmission at the Meadow Creek site, the power purchase agreements from three of the projects may be assigned to Ridgeline Energy. If the Cedar Creek projects are assigned to Ridgeline, the scheduled operation date moves up to Dec. 31, 2012, which qualifies the projects to receive Department of Treasury grants and other tax incentives before they expire.

Even though two of the five projects won't be built, the output from the three remaining projects will be the same as was agreed to with all five original projects: an annual nameplate capacity not to exceed 133.4 megawatts with annual output not to exceed 50 average megawatts per month.

Ridgeline's Meadow Creek site is smaller but has more wind capacity than the Cedar Creek location. However, Ridgeline's site has only 80 megawatts of transmission capacity and will need to acquire another 40 MW of capacity to accommodate the former Cedar Creek projects.

If no additional transmission becomes available, then part of the projects may revert to the Cedar Creek site. (If Congress extends tax credits, all of the projects could remain at the original site.)

http://www.puc2.idaho.gov/intranet/cases/elec/PAC/PACE1101/staff/20111221PRESS%20RELEASE.HTM

December 2011: Commission staff met informally with the developer of two Idaho Power wind projects, Grouse Creek Wind Parks, to see if that case could be settled. The Grouse Creek projects were the only two of the 12 Idaho Power projects that appealed to the state Supreme Court. Oral argument in that case is set for March 7, 2012.

January 2012: Wind opponents declare their intent to introduce several pieces of legislation to limit further development of wind. Idahoans for Responsible Wind Energy forms into a new group called the Energy Integrity Project.

http://www.energyintegrityproject.org/Home_Page.html

Small-power renewable projects added during 2011

Sahko Hydro Project near Filer, 0.5 MW, Idaho Power, IPC-E-10-37
http://www.puc.idaho.gov/internet/press/011311_IPCoFilerhydro.htm

Hidden Hollow Energy 2 at Ada County Landfill, 3.2 MW, Idaho Power, IPC-E-10-44
http://www.puc.idaho.gov/internet/press/021811_IPCoAdalandfill.htm

Hazelton A Hydroelectric near Jerome, 8.1 MW, Idaho Power, IPC-E-10-45
http://www.puc.idaho.gov/internet/press/021811_IPCoHazeltonhydro.htm

Exergy-Rogerson wind projects (Deep Creek, Cottonwood, Rogerson Flat, Salmon Creek) near Rogerson, each up to 10 MW, Idaho Power, IPC-E-10-47, -48, -49 and -50.
http://www.puc.idaho.gov/internet/press/021811_IPCoRogersonwindprojects.htm

Cargill, Inc. biogas-fueled digester at dairy farm near Roberts, 1.7 MW, PacifiCorp (Rocky Mountain Power), PAC-E-11-08
http://www.puc.idaho.gov/internet/press/060911_RMPCargill.htm

Clark Canyon Hydro, near Dillon, Mont., 4.7 MW, Idaho Power, IPC-E-11-09
http://www.puc.idaho.gov/internet/press/072611_IPCoClarkCanyon.htm

Interconnect Solar, near Murphy, 20 MW, Idaho Power, IPC-E-11-10
http://www.puc.idaho.gov/internet/press/102411_IPCoInterconnectSolar.htm