Electrical Power in Idaho

Idaho residents consistently enjoy some of the least expensive electric service in the nation, according to surveys conducted by the National Association of Regulatory Utility Commissioners (NARUC), the Edison Electric Institute and the Energy Information Administration of the U.S. Department of Energy.

Idaho Power Company

2004 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
360,462 Residential Customers/$0.0602
72,382 Commercial Customers/$0.0467
120 Industrial Customers/$0.0337

Avista Utilities

2004 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)
94,476 Residential Customers/$0.0640
15,143 Commercial Customers/$0.0675
516 Industrial Customers/$0.0412

2004 Average Number of Customers/Avg. Revenue/kwh
(Computed from data available in FERC Form 1 Annual Reports)

PacifiCorp/Utah Power

49,439 Residential Customers/$0.0404
7,003 Commercial Customer/$0.0595
5,433 Industrial Customer/$0.0341

Year in Review

Natural gas prices and determining a fair price for rapidly growing wind projects in southern Idaho were the major issues brought before the Idaho Public Utilities Commission during 2005.

Soaring natural gas prices threatened to propel winter heating bills by year's end. U.S. natural gas prices have been edging higher for years and shot up sharply after two hurricanes damaged production in the Gulf of Mexico along with onshore processing facilities.

Read more about Intermountain Gas case, INT-G-05-02:
http://www.puc.state.id.us/internet/press/093005_IntGasPGA.htm

While the impacts of the hurricanes were not included in this year's purchased gas cost adjustments, Idaho's natural gas companies were not immune from the volatile wholesale natural gas markets.

In southern Idaho, Intermountain Gas sought and received a purchased gas cost adjustment that increased rates an average 27.6 percent. The Weighted Average Cost of Gas, or WACOG – that portion of a customer's bill that reflects cost of gas increases – was increased from 55.5 cents per therm to 73.2 cents. The total average price per therm for a residential customer, including the base rate and the WACOG, is about $1.14. None of the money raised by the 27.6 percent increase – 67.6 million – goes to increase Intermountain's earnings, but it is used to allow the company to recover its gas supply expenses. The company has not filed for a base rate increase since 1985.

In northern Idaho, Avista Gas customers received an average 23.8 percent increase to cover the costs that company incurred buying gas for its 110,000 Idaho customers.

Read more about Avista gas case, AVU-G-05-02:
http://www.puc.state.id.us/internet/press/102705_AvuGasPGA.htm

The WACOG increased from 55.74 cents per therm to 76.79 cents. The total average price per therm for a residential customer climbed to $1.18.

What is the purchased gas cost adjustment?
Both Avista Gas and Intermountain Gas participate with the commission in a purchased gas cost adjustment, or PGA, process. If the utilities spend more to purchase gas than has been included in customer rates, it can seek a temporary increase. An increase is granted if the commission finds the above-normal gas purchase expenses made by the utility were prudently incurred. In recent years, gas companies have sought large purchased gas adjustments because the wholesale gas market has been so volatile. The PGA can sometimes work to the benefit of customers. If wholesale prices drop significantly and the company spends less to buy gas than it collects from customers, it must decrease rates.

Electric rates

Natural gas price hikes contributed also to increases in electric rates. Nearly half the rapid growth in natural gas demand comes from electric utilities building natural gas power plants.

Read more about Idaho Power's 2005 rate case, IPC-E-05-28:
http://www.puc.state.id.us/internet/press/112205_IPCoratecase.htm
Read more about Idaho Power's 2004 rate case, IPC-E-05-10, -14, -15:
(http://www.puc.state.id.us/internet/press/052705_IPCPCABntMtntax.htm

The commission is now considering a November 2005 request by **Idaho Power** for a base rate increase of 7.8 percent for all customer classes.

The company cites an increase in operating costs for the increase. Idaho Power is seeking a return on rate base of 8.42 percent and return on equity of between 11 and 12 percent.

If approved, average residential rates would increase from 5.74 cents per kWh to 6.19 cents. Small commercial rates would increase from 7.16 cents to 7.72 cents and large commercial rates from 3.91 cents to 4.22 cents. Irrigation rates would increase from 4.42 cents to 4.76 cents.

In the spring of 2004, Idaho Power received a base rate increase of 6.3 percent effective June 1. Most of the 2004 increase, about 4.5 percent, was the result of a negotiated settlement between the company and the commission over a disputed tax expense issue arising from the 2003 Idaho Power rate case. Half of that 4.5 percent, 2.2 percent, expires June 1, 2006. The remaining 1.8 percent allowed Idaho Power to cover the costs of the Bennett Mountain natural gas power plant and its transmission and interconnection facilities.

Because of the base rate increases, Idaho Power did not seek an increase in its power cost adjustment (PCA) surcharge. (*See definition at right.*)

<u>What is the power cost surcharge (PCA)?</u>
Customer rates are divided into two components, the base rate and the power cost adjustment or PCA. (In the case of gas utilities, this same mechanism is called the "purchased gas cost adjustment" or PGA.) The normal costs for supplying power are recovered in the utility's base rates. However, a utility may incur higher than normal costs from unusual circumstances, such as low water conditions or higher than anticipated market conditions. The PCA annually increases (through a one-year surcharge) or decreases (with a credit) customer rates to account for above-normal or below-normal power supply costs. Yearly PCA adjustments, up or down, do not affect the utility's earnings. The money collected from the PCA is essentially a pass-through, passing directly from the utility to its power suppliers. ***Simpler definition:*** The base rate includes the cost of everyday operations. The power cost adjustment includes the variable costs of energy.

Customers of **PacifiCorp**, doing business as Utah Power in eastern Idaho, received a 4.8 percent increase in base rates effective Sept. 16, 2004. However, on that same date, a 3.1 percent surcharge the company implemented to recover tax expenses expired. So the net increase to Utah Power customer bills was about 1.7 percent.

PacifiCorp initially requested an increase of 12.5 percent, which would have resulted in a net increase of 9.4 percent with the expiration of the surcharge.

The case was settled by stipulation rather than formal hearings. Monsanto, PacifiCorp's largest customer -

with about 40 percent of the company's Idaho load – was the only one of several parties that didn't sign the settlement. Monsanto objected to commission staff's proposal that it be subject to a "tariff standard," rather than the current "contract standard." The tariff standard would allow for contract rates to be increased whenever other customer classes receive a base rate increase.

Read more about Utah Power's rate case, PAC-E-05-01:
http://www.puc.state.id.us/internet/press/072205_PACsettle.htm

The commission eventually agreed to remove the paragraph of the settlement that would subject contract customers to a tariff standard. The commission did so because PacifiCorp said it intended to file a rate case by no later than April 29, 2006. Further, a new contract with Monsanto will need to be negotiated, also next year. The commission said the contract/tariff standard could be addressed during the 2006 case.

Avista Utilities, with customers in five northern Idaho counties, received a 1.9 percent increase in base rates to include the purchase costs for the 280-megawatt Coyote Springs II natural gas plant in Morrow, County, Oregon. However, the increase did not effect customer bills because the company also elected to decrease its power cost adjustment by the same 1.9 percent and extend the PCA surcharge another 12 months.

For residential customers, the base rate increased from 5.7 cents per kWh to 5.84 cents for use under 600 kWh and from 6.5 cents per kWh to 6.61 cents for use of more than 600 kWh. The PCA decreased from 0.286 cents per kWh to 0.163 cents. With the year extension, the surcharge remains in place through September 2007.

MidAmerican seeking to acquire PacifiCorp

PacifiCorp, which serves about 60,000 customers in southeastern Idaho, has applied for commission approval of Iowa-based MidAmerican Energy Holdings Company's bid to purchase PacifiCorp.

Read more about MidAmerican and PacifiCorp, PAC-E-05-08:
http://www.puc.state.id.us/internet/press/081805_PACMidAmer.htm

The merger must be approved by public utility commissions in all six states where PacifiCorp has customers. At this report's printing, the merger was recommended for approval in Utah and California. Idaho's commission was in the process of initiating settlement discussions among the parties involved in the case.

MidAmerican, whose principal owner is Berkshire Hathaway, Inc., headed by billionaire investor Warren Buffett, is offering a sale of common stock valued at $9.4 billion.

The commission's job, as defined in state statutes, will be to ensure that 1) the transaction is in the public interest, 2) rates will not increase as a direct result of the transaction and 3) MidAmerican has the intent and financial ability to operate and maintain PacifiCorp's operation in Idaho.

Integrating wind into Idaho's generation mix

The increasing development of wind as an energy source posed some new questions for the commission, regulated utilities and wind developers. Idaho Power, later joined by PacifiCorp and Avista, wanted commission approval to suspend the company's federal obligation to buy wind power from independent developers of small wind projects to allow time to further examine a fair price for wind given its unpredictable output.

The commission denied Idaho Power's request for a moratorium, but it temporarily lowered the size of non-firm wind projects that can qualify for a published government rate from 10 megawatts to 100 kilowatts. *(See definition of PURPA rate at right.)* The lower limit remains in place until the questions raised by the utilities are addressed.

What is PURPA?
The Public Utility Regulatory Policies Act was passed by Congress during the energy crisis of the late 1970s. One of its stated goals is to encourage development of renewable energy technologies as alternatives to burning fossil fuels or constructing new power plants. The federal act requires that electric utilities offer to buy power produced by small power producers or co-generators who obtain Qualifying Facility (QF) status. The published rate to be paid project developers is set by state commissions and is to be equal to the cost the electric utility avoids if it would have had to generate the power itself or purchase it from another source.

The 100 kW limit does not apply to all PURPA contracts, but only wind contracts that are not "firm," meaning they cannot be backed up by an alternative energy source when wind fails to generate the amount of energy the wind developer commits to deliver to the power company. To ensure system reliability, Idaho Power stated that intermittent wind resources must be "firmed" by backup power. A company 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. Idaho Power said the added cost of backup power should be included in the calculation of rates for wind.

Wind developers argued that a performance band established by the commission in a 2004 case that penalizes wind producers for not falling within 90 to 110 percent of their projected output sufficiently deals with the firm vs. non-firm characteristics of wind.

Read more about the wind moratorium case, IPC-E-05-22:
http://www.puc.state.id.us/internet/press/080405_IPCowind.htm

The commission said the performance band "may not capture the integration requirements and operational demands placed on the utility by intermittent generation and that the integration costs associated with the same may not be fully reflected in the published avoided cost rates." Federal PURPA law stipulates no utility be required to pay more than its avoided cost.

Idaho Power also argued that the higher PURPA price awarded small wind developers, about $61 per MWh, artificially inflated the bids the company sought from large wind developers.

However, the commission said it found no persuasive evidence bids were affected by PURPA rates. The case was still open at the time this report went to press.

In 2005, the commission approved wind projects totaling 70 average megawatts and had another 40 average megawatts waiting approval at year's end.

All of the developers signed contracts with Idaho Power.

Four projects are in the Hagerman area, two in the Burley area and another is an agreement by Idaho Power to purchase 10 average megawatts from a Montana wind project 100 miles northwest of Billings.

Read more about each of the projects:
Two Burley area projects:
IPC-E-05-17 and IPC-E-05-18
http://www.puc.state.id.us/internet/press/070105_IPCoBurleywind.htm

Montana wind project:
IPC-E-05-24
http://www.puc.state.id.us/internet/press/100405_IPCoArrowrockwind.htm

Four Hagerman area projects:
IPC-E-05-06, -07, -08, -09
http://www.puc.state.id.us/internet/press/042605_IPCowindprojects.htm

Proposed wind projects:
IPC-E-05-30, -31, -32, -33
http://www.puc.state.id.us/internet/press/110805_IPCowindprojects.htm

The four projects awaiting commission approval are Milner Dam Wind Park west of Burley, Lava Beds Wind Park between Blackfoot and Arco, Notch Butte Wind Park between Twin Falls and Shoshone and Salmon Falls Wind Park near Hagerman. Each of the projects will deliver 10 average megawatts.

All of the projects were on their way toward development when the commission lowered the size of projects that can qualify for the PURPA rate and are therefore exempt from the lower limit.

Idaho Power seeks to buy energy from Ada landfill

Wind isn't the only source of renewable power recently made available to Idaho utilities.

Early in 2005, the commission approved a sales agreement between Idaho Power and U.S. Geothermal for geothermal energy and Idaho Power is waiting commission approval to buy energy from a plant that produces energy as a byproduct of waste processing at a Boise landfill.

Boise-based U.S. Geothermal is planning to build a geothermal generating facility, the Raft River

Geothermal Power Plant, near Malta. When completed in mid-2006, it is expected to be the first geothermal power plant in the Pacific Northwest.

Read more about:
The U.S. Geothermal contract, IPC-E-05-01
http://www.puc.state.id.us/internet/press/012505_IPcUSGeoTh.htm
Ada landfill contract, IPC-E-05-29
http://www.puc.state.id.us/internet/press/110905_IPColandfillgas.htm

Under the 20-year contract, U. S. Geothermal agrees to sell Idaho Power up to 10 average megawatts per month. The Raft River facility will interconnect with the Raft River Rural Electric Cooperative system and wheel its energy to Idaho Power over transmission lines owned by the Raft River Co-Op and the Bonneville Power Administration.

Idaho Power is seeking commission approval of a purchase agreement with G2 Energy Hidden Hollow LLC to buy the energy output from the Hidden Hollow Landfill on Seaman's Gulch road north of Boise.

The electricity is produced as a byproduct of the landfill's operations. The plant would be able to produce, at full capacity, 3.2 megawatts. The plant is scheduled to be in operation by March 1, 2005.

Planning for the future

The commission requires regulated utilities to file an Integrated Resource Plan (IRP) every two years. The 10-year growth plan projects future load requirements and how utilities plan to deliver low-cost, reliable energy to its customers.

Idaho Power's IRP was approved by the commission in April. It projects an increase in customer households from 320,000 to more than 380,000 by the end of 2013. Idaho Power continues to plan future power supply sources based on a "worse than median" water conditions. The utility used to count on up to 60 percent of its generation to come from the utility's own hydroelectric dams, but a sixth consecutive year of drought has forced a greater dependency on other sources.

Idaho Power plans to increase its power supply by about 800 average megawatts. The company's average amount of electricity need to serve its customers is 1660 aMW. The company also plans to increase its capacity (the amount of electricity needed to serve its customers at peak-use times) by another 940 megawatts. Its current peak load capacity (reached in the summers of 2002 and 2003) is 3000 megawatts.

Idaho Power's long-term plan calls for 500 MW from coal-fired generation, 350 MW from wind, 100 MW from geothermal, 88 MW from natural gas, 76 MW from demand response programs, 62 MW from distributed generation and market purchases and 48 MW of byproduct generated from combined heat and power facilities and another 48 MW from energy efficiency programs.

The commission lauded the company's increased focus on conservation and development of renewable energy sources. However, commissioners said the company continues to rely too heavily on gas-fired generation to meet summer peak demand and should do more to implement conservation programs.

Avista Utilities submitted a plan in October that is still waiting commission approval. Avista projects it will grow to 350,000 customers in its three-state territory by 2007 – up from the current approximate 330,000 – and to 485,000 customers in 2026. There are about 110,000 customers in northern Idaho.

Read more about:
Idaho Power's IRP, IPC-E-04-18 at:
http://www.puc.state.id.us/internet/press/042205_IPCoIRP.htm
Avista's IRP, AVU-E-05-08 at:
http://www.puc.state.id.us/internet/press/100605_AVUIRP.htm
PacifiCorp's IRP, PAC-E-05-02 at:
http://www.puc2.idaho.gov/intranet/cases/elec/PAC/PACE0502/ordnotc/20050826ACCEPTANCE%20OF%20FILING.PDF

Without adding to its generation, the company would begin to experience energy deficits in 2010. To meet growth, the company's preferred resource portfolio by 2016 is a mix of generation sources, including 400 megawatts of wind, 250 MW from coal and another 80 MW from small renewable projects. The company is not proposing any additional natural gas-fired generation due to the high level of natural gas generation already in the company's portfolio and the rising price of natural gas.

PacifiCorp plans to meet projected electrical demands in the next 10 years by adding three natural gas power plants and two coal plants in its six-state territory and increasing its capacity through conservation programs. In addition to the new coal and natural gas plants, PacifiCorp is continuing to pursue a commitment it made two years ago to procure 1,400 megawatts in renewable resources, such as wind.

PacifiCorp projects an annual growth in electrical demand of 3.8 percent in its three eastern states (Utah, Wyoming and Idaho) and 1.5 percent in its western states (Oregon, Washington and California). Without developing further resources, the utility would face a shortfall by 2009 and be 2800 MW short by 2015.

The company is proposing to add 2,629 MW from two coal and two natural gas plants in its eastern territory and one natural gas plant in its western territory. Specific sites for all the plants have not yet been determined and none are proposed in Idaho. PacifiCorp also proposes to add 1,200 MW in purchased power from other suppliers and 100 MW in contracts from small-power producers through federal PURPA requirements. It also proposes the addition of 177 MW from load-control programs involving residential and commercial air conditioners, irrigation and commercial and industrial lighting. PacifiCorp hopes to produce 250 average megawatts in energy and capacity savings achieved through technological improvements in appliances, equipment and buildings.

Two major issues impacting PacifiCorp's resource choices are the future cost of natural gas and the future cost of or constraints on air emissions – carbon dioxide emissions in particular – that may be imposed on the company by government regulation.

Finding efficiencies

Two of Idaho's major utilities sought commission approval to add or modify efficiency riders to electric bills to fund conservation and demand-side management (DSM) programs. Money generated from efficiency riders currently in place for **Idaho Power** and **Avista** goes to fund DSM programs designed to offset the growth in demand for new power plants and to reduce the need for utilities to acquire power from more expensive sources to meet growing customer demand. Money from the rider does not go to increase utility earnings.

The commission adopted an Idaho Power proposal to change the way its Energy Efficiency Rider approved in 2002 is assessed. The rider was set in 2002 at the equivalent of 0.5 percent of each customer's base bill or an averaged flat fee of 30 cents per month for the residential class. Beginning June 1, 2005, the rider increased to 1.5 percent of each customer's base bill, but the amount of the rider varies by consumption. The commission turned down Idaho Power's request to increase the rider again on June 1, 2007, to 2.4 percent of base revenue.

For customers who use less than 330 kWh per month, the charge will stay about the same or decrease slightly. The rider increases with consumption, but is capped to go no higher than $1.75 per month for the residential class. For the irrigation class, the rider also increases with use but is capped to go no higher than $50 per month per meter.

PacifiCorp, or **Utah Power**, has an application pending before the commission for a 1.5 percent rider to pay for a number of conservation programs.

Read more about:
Idaho Power's efficiency rider, IPC-E-04-29, at:
http://www.puc.state.id.us/internet/press/051305_IPCoDSMrider.htm
About PacifiCorp's proposed rider, PAC-E-05-10, at:
http://www.puc.state.id.us/internet/press/100305_PACDSMcharge.htm

The rider, which would cost an average residential customer who uses 790 kilowatt-hours a month about $1 per month, will raise $1.8 million annually to fund energy efficiency programs for residential, irrigation and commercial and industrial customers. The 1.5 percent rider, if approved, would begin appearing on customer bills after Jan. 1, 2006.

Some of the programs Utah Power seeks to fund include no-cost equipment exchanges and financial incentives for efficiency measures for irrigators, mechanical and lighting upgrades for commercial and industrial customers, a refrigerator recycling program for residential customers and more money devoted to a low-income weatherization program. The company is hoping that all the programs, if approved, will save about 50 megawatts for each of the next three years.

Avista Utilities has had an efficiency rider in place since 1995. The amount varies, but is currently set at 1.25 percent.

In addition to efficiency riders, utilities have initiated or expanded a number of demand-side management programs in the past year.

The commission approved two voluntary pilot programs proposed by **Idaho Power** in the Emmett area.

The programs , *Energy Watch* and *Time-of-Day*, offer financial incentives for customers who, with the use of automated meter readers, shift their electrical use away from those peak times when energy consumption is at its highest and electricity is the most expensive.

Idaho Power installed automated meter readers (AMR) in the Emmett and Letha areas. Some AMR systems have the ability to inform customers of current electric prices, potentially allowing them to manage their electrical use and reduce their bills. AMR allows customers to receive real-time pricing and use information, thereby helping them to shift their use to non-peak times.

Under *Energy Watch*, Idaho Power allows volunteer participants to pay the less expensive non-summer rate (5.08 cents per kWh), except during the company's selected Energy Watch periods, when the rate will be 20 cents per kWh. The company will notify volunteer customers either by telephone or by e-mail by 4 p.m. a day before the higher-priced Energy Watch period. Energy Watch periods can occur on weekdays from June 15 through August 15 for four hours between 5 and 9 p.m. The company said Energy Watch periods will occur on no more than 10 days from June 15 to August 15 for a total of 40 hours.

The *Time-of-Day Pilot Program* allows volunteers to receive electricity for only 4.97 cents per kWh for all the electrical use they can shift to the off-peak times of 9 p.m. to 7 a.m. on weekdays and during all hours on Saturday, Sunday and July 4. Mid-peak times, during which customers will pay 5.8 cents per kWh, will be from 7 a.m. to 1 p.m., Monday through Friday. On-peak periods, during which customers will pay 6.48 cents per kWh, will be from 1 to 9 p.m., Monday through Friday. This program will be in effect for the summer season of June 1 through Aug. 31.

Idaho Power will file a status report and preliminary findings by the end of 2005 and submit a final report upon completion of the program in 2006.

Idaho Power is phasing in automated meter reader technology and should soon be able to offer programs like these to a wider segment of its customer base.

The commission also approved Idaho Power's proposal to expand a volunteer *air conditioner cycling program* to include residential customers in Ada and Canyon counties and in the Emmett area. The company anticipates that within five years the program will have 40,000 volunteer participants, which, with an average load reduction of 1.1 kW per participant, equates to 44.4 megawatts of electrical reduction during peak-use times of June, July and August.

Customers who volunteer to participate have their air conditioners turned on and off (cycled) by direct load control switches installed by Idaho Power. Volunteers are given a $7 credit for each month they participate. The program started during summer 2004 with residential customers in Boise and Meridian.

The commission approved a proposal by **PacifiCorp** to allow its larger customers an opportunity to buy renewable energy in bulk at a reduced rate.

PacifiCorp already has a renewable purchase option called "Blue Sky" for primarily residential customers. However, the purchase price for energy derived from wind, geothermal or solar sources is too expensive for commercial and industrial customers who want to buy renewable energy in much larger quantities.

Under the Blue Sky program, PacifiCorp allows residential customers to buy renewable energy for an additional $1.95 per month for every 100 kilowatt-hours purchased.

Like the residential program, the bulk-purchase option for larger customers is voluntary. Under the bulk-purchase option, customers who agree to enroll for a minimum of one year and agree to purchase at least 101 blocks of 100-kWh of renewable energy will pay 70 cents for every block. That’s down from the $1.95 per 100-kWh block customers who buy in smaller amounts would pay.

SERVICE AREAS OF INVESTOR OWNED ELECTRIC UTILITIES IN IDAHO