IDAHO PUBLIC UTILITIES COMMISSION

2017 Annual Report

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Idaho Public Utilities Commission

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This report can be accessed online from the Commission's Website at www.puc.idaho.gov. Click on "File Room," in the upper-left-hand-corner and then on "IPUC 2017 Annual Report."

Front cover photograph courtesy of Avista Utilities.

Idaho Public Utilities Commission
P.O. Box 83720, Boise, ID 83720-0074

C.L. Butch Otter, Governor

Paul Kjellander, Commissioner
Kristine Raper, Commissioner
Eric Anderson, Commissioner

December 1, 2017

The Honorable C.L. "Butch" Otter
Governor of Idaho
Statehouse
Boise, ID 83720-0034

Dear Governor Otter:

It is my distinct pleasure to submit to you, in accordance with Idaho Code §61-214, the Idaho Public Utilities Commission 2017 Annual Report. This report provides a detailed description of the most significant cases, decisions and other activities throughout 2017. The financial report on Page 8 offers a summary of the commission's budget through the conclusion of Fiscal Year 2017, which ended June 30, 2017.

It has been a privilege and honor serving the people of Idaho this past year.

Sincerely,

Paul Kjellander

President, Idaho Public Utilities Commission

COMMISSIONERS

PAUL KJELLANDER

Paul Kjellander serves as president of the Idaho Public Utilities Commission, having been appointed to his current six-year term in 2017 by Gov. C.L. "Butch" Otter. His term expires in 2023.

It is Commissioner Kjellander's second term in his second stint on the Commission, having previously served from January 1999 until October 2007. Gov. C.L. "Butch" Otter reappointed Kjellander in April 2011, following his service as administrator of the newly created state Office of Energy Resources (OER).

A member of the National Association of Regulatory Commissioners' board of directors, Kjellander is chairman of the association's Committee on Telecommunications and serves as NARUC representative to the North American Numbering Council. He previously served on NARUC's Committee on Consumer Affairs and its Electricity Committee.

Kjellander is an at-large member of the National Council on Electricity Policy, which is funded by the US Department of Energy and managed by NARUC.

Kjellander is also a member of the Federal Communications Commission's 706 Joint Board, and has served as chairman of the FCC's Federal-State Joint Board on Jurisdictional Separations.

During his time at OER, which is now known as the Office of Energy and Mineral Resources, Kjellander created an aggressive energy efficiency program funded through the federal American Recovery and Reinvestment Act of 2009. He also served on the board of the National Association of State Energy Officials.

Before joining the Commission in 1999, Kjellander was elected to three terms in the Idaho House of Representatives, where he served from 1994 to 1999. As a legislator, Kjellander served on a number of committees, including the House State Affairs, Judiciary and Rules, Ways and Means, Local Government and Transportation. During his final term in office, Kjellander was elected chairman of the House Majority Caucus.

Kjellander has also served as director of Boise State University's College of Applied Technology Distance Learning, program head of broadcast technology, station manager of BSU Radio Network, director of the Special Projects Unit for BSU Radio and BSU Radio's director of News and Public Affairs.

He earned undergraduate degrees in communications, psychology and art from Muskingum College in Ohio. He also has a master's degree in telecommunications from Ohio University.

COMMISSIONERS

KRISTINE RAPER

Kristine Raper was appointed to the commission on Feb. 19, 2015 by Gov. C.L. "Butch" Otter. Her term expires in January 2021.

Commissioner Raper serves on the Electricity Committee of the National Association of Regulatory Utility Commissioners (NARUC) and is the incoming president of the Western Conference of Public Service Commissioners.

Raper is a member of the Body of State Regulators for the California ISO's Energy Imbalance Market. She is also a member of the State-Provincial Steering Committee.

Raper recently testified before Congress regarding Public Utility Regulatory Policies Act (PURPA), defending Idaho's decisions regarding the federal law. Commissioner Raper has also testified on PURPA issues before the Idaho Supreme Court, District Court and the Federal Energy Regulatory Commission, which enforces PURPA.

Raper previously served on the Member Advisory Committee of the Western Electric Coordinating Council (WECC).

Prior to her appointment to the Idaho Public Utilities Commission, Raper served for seven years as a deputy attorney general assigned to the Commission. During her time as an attorney for the Commission, Raper was involved in electric, gas, water and telecommunications cases, with an emphasis on PURPA-related matters.

Before her service as a deputy attorney general, Commissioner Raper served for eight years as a law clerk to R.D. Maynard of the Idaho Industrial Commission. There, Raper developed expertise in state worker's compensation law and unemployment matters appealed through the Idaho Department of Labor.

Raper was born in Delaware and moved to Utah with her family in the early 1980s. She moved to Boise in 1990 to attend Boise State University and earned a bachelor of science in criminal justice in 1995. She received her juris doctor from the University of Idaho in 2001.

The commissioner and her husband, Mark, share three children.

COMMISSIONERS

ERIC ANDERSON

Eric Anderson was appointed to the Commission in December 2015. His term expires in January 2019.

Commissioner Anderson serves on the National Association of Regulatory Utility Commissioners' Committee on Water as well as its Committee on International Relations.

Before his appointment by Gov. C.L. "Butch" Otter, Anderson served five terms in the Idaho Legislature, from 2004-2014. Anderson was chairman of the House Ways and Means Committee in his final term in the state Legislature.

As a member of the state House of Representatives, Anderson served on a number of committees, including Environment, Energy and Technology; Commerce and Human Resources; Resources and Conservation; Business; and State Affairs. He also chaired a legislative Interim Subcommittee on Renewable Energy.

Anderson received a bachelor of art degree in political science and government from Eastern Washington University in 1979.

A general contractor and real estate broker, Anderson served as director and vice president of Sandpoint-based Northern Lights Inc., an electric cooperative in Sandpoint, prior to his appointment to the Commission.

He has also served as a director of the Idaho Consumer-Owned Utilities Association, the National Rural Electric Cooperative Association and the Idaho Energy Resources Authority. He is a past member and advisor to the Pacific States Marine Fisheries Council and the Pacific Northwest Economic Region's Executive Council.

FINANCIAL SUMMARY FUND 0229*

Fiscal Years 2013-2017

Description	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
Personnel Costs	$3,491,500	$3,528,900	$3,563,500	$3,835,900	$4,070,200
Communication Costs	$31,300	$31,000	$23,500	$28,700	$23,400
Employee Development Costs	$55,600	$53,200	$99,200	$98,700	$81,400
Professional Services	$9,700	$12,300	$8,500	$8,600	$11,900
Legal Fees	$551,600	$519,700	$538,400	$579,400	$482,100
Employee Travel Costs	$123,600	$141,100	$152,500	$159,200	$173,900
Fuel & Lubricants	$4,700	$2,700	$5,600	$2,900	$4,900
Insurance	$3,100	$4,400	$4,300	$2,000	$3,500
Rentals & Leases	$276,100	$584,600	$308,600	$223,800	$147,000
Misc. Expenditures	$117,000	$104,700	$84,400	$104,300	$114,900
Computer Equipment	$29,200	$66,400	$73,600	$52,200	$44,700
Office Equipment	$13,000	$11,900	$16,500	$8,100	$4,200
Motorized/Non-Motorized Equip	$0	$0	$32,500	$0	$0
Specific Use Equipment	$0	$0	$0	$1,700	$4,500
Total Expenditures	$4,706,400	$5,060,900	$4,911,100	$5,095,100	$5,166,600
Fund 0229-20 Appropriation	$4,916,800	$5,061,700	$5,595,600	$5,766,500	$5,902,700
Unexpended Balance	$210,400	$800	$684,500	$671,400	$736,100

* This summary represents assessment-funded expenses only. It does not include federal or other funds.

COMMISSION STRUCTURE AND OPERATIONS

Under state law, the Idaho Public Utilities Commission supervises and regulates Idaho's investor-owned utilities – electric, gas, telecommunications and water – assuring adequate service and affixing just, reasonable and sufficient rates.

The commission does not regulate publicly owned, municipal or cooperative utilities.

The governor appoints the three commissioners with confirmation by the Idaho Senate. No more than two commissioners may be of the same political party. The commissioners serve staggered six-year terms.

The governor may remove a commissioner before his/her term has expired for dereliction of duty, corruption or incompetence.

The three-member commission was established by the 12th Session of the Idaho Legislature and was organized May 8, 1913 as the Public Utilities Commission of the State of Idaho. In 1951 it was reorganized as the Idaho Public Utilities Commission. Statutory authorities for the commission are established in Idaho Code titles 61 and 62.

The IPUC has quasi-legislative and quasi-judicial as well as executive powers and duties.

In its quasi-legislative capacity, the commission sets rates and makes rules governing utility operations. In its quasi-judicial mode, the commission hears and decides complaints, issues written orders that are similar to court orders and may have its decisions appealed to the Idaho Supreme Court. In its executive capacity, the commission enforces state laws and rules affecting the utilities and rail industries.

Commission operations are funded by fees assessed on the utilities and railroads it regulates. Annual assessments are set by the commission each year in April within limits set by law.

The commission president is its chief executive officer. Commissioners meet on the first Monday in April in odd-numbered years to elect one of their own to a two-year term as president. The president signs contracts on the commission's behalf, is the final authority in personnel matters and handles other administrative tasks. Chairmanship of individual cases is rotated among the commissioners.

COMMISSION STRUCTURE AND OPERATIONS

The commission conducts its business in two types of meetings – hearings and decision meetings. Decision meetings are typically held once a week, usually on Monday.

Formal hearings are held on a case-by-case basis, sometimes in the service area of the impacted utility.

IPUC hearing room

These hearings resemble judicial proceedings and are recorded and transcribed by a court reporter.

There are technical hearings and public hearings.

At technical hearings, formal parties who have been granted "intervenor status" present testimony and evidence, subject to cross-examination by attorneys from the other parties, staff and the commissioners. At public hearings, members of the public may testify before the commission.

Many public hearings are conducted in cities and towns that are part of the service territory of the utility seeking a rate increase. In less contested rate cases, the commission will sometimes conduct hearings telephonically to save expense and allow customers to testify from the comfort of their own homes. Commissioners and other interested parties gather in the Boise hearing room and are telephonically connected to ratepayers who call in on a toll-free line to provide testimony or listen in to those testifying.

IPUC headquarters at 472 W. Washington St. in downtown Boise

The commission also conducts regular decision meetings to consider issues on an agenda prepared by the commission secretary and posted in advance of the meeting. These meetings are usually held Mondays at 1:30 p.m., although by law the commission is required to meet only once a month. Members of the public are welcome to attend decision meetings.

Typically, decision meetings consist of the commission's review of decision memoranda prepared by commission staff. Minutes of the meetings are taken. Decisions reached at these meetings may be either final or preliminary, but subsequently become final when the commission issues a written order signed by a majority of the commission. Under the Idaho Open Meetings Law, commissioners may also privately deliberate matters that have been fully submitted.

COMMISSION STAFF

OUR MISSION

- ***Determine fair, just and reasonable rates and utility practices for electric gas and water consumers.***
- ***Ensure that delivery of utility services is safe, reliable and efficient.***
- ***Ensure safe operation of pipelines and rail carriers within the state.***

To help ensure its decisions are fair and workable, the Commission employs a staff of about 50 people – engineers, rate analysts, attorneys, accountants, investigators, economists, secretaries and other support personnel. The Commission staff is organized into three divisions – administration, legal and utilities.

The staff analyzes each petition, complaint, rate-increase request or application for an operating certificate received by the Commission. In formal proceedings before the Commission, the staff acts as a separate party to the case, presenting its own testimony, evidence and expert witnesses. The Commission considers staff recommendations along with those of other participants in each case - including utilities, public, agricultural, industrial, business, environmental and consumer groups.

Administration

The Administrative Division is responsible for coordinating overall IPUC activities. It includes the three commissioners, a policy analyst, a commission secretary, an executive administrator, an executive assistant, public information officer and support personnel.

The policy analyst is an executive level position that reports directly to the commissioners with policy and technical consultation and research support regarding major regulatory issues in the areas of electricity, telecommunications, water and natural gas. Strategists are also charged with developing comprehensive policy strategy, providing assistance and advice on major litigation before the commission, public agencies and organizations.
Contact Stephen Goodson, Policy Analyst, (208) 334-0323.

The commission secretary, a post established by Idaho law, keeps a precise public record of all commission proceedings. The secretary issues notices, orders and other documents to the proper parties and is the official custodian of documents issued by and filed with the commission. Most of these documents are public records.
Contact Diane Hanian, Commission Secretary, (208) 334-0338.

The executive administrator has primary responsibility for the commission's fiscal and administrative operations, preparing the commission budget and supervising fiscal, administration, public information,

COMMISSION STAFF

personnel, information systems, rail section operations and pipeline safety. The executive administrator is the primary contact for matters concerning Information Technology, Fiscal and Human Resources. He also serves as a liaison between the commission and other state agencies and the Legislature.
Contact Joe Leckie, Executive Administrator, (208) 334-0331.

Legal

Five deputy attorneys general are assigned to the commission from the Office of the Attorney General and have permanent offices at IPUC headquarters. The IPUC attorneys represent the staff in all matters before the commission, working closely with staff accountants, engineers, investigators and economists as they develop their recommendations for rate case and policy proceedings.

In the hearing room, IPUC attorneys coordinate the presentation of the staff's case and cross-examine other parties who submit testimony. The attorneys also represent the commission itself in state and federal courts and before other state or federal regulatory agencies.
Contact Karl Klein, Legal Division Director, (208) 334-0320.

Utilities Division

The Utilities Division, responsible for technical and policy analysis of utility matters before the commission, is divided into five sections.
Contact Randy Lobb, Utilities Division Administrator, (208) 334-0350.

The Accounting Section of six auditors and one supervisor audits utility books and records to verify reported revenue, expenses and compliance with commission orders. Staff auditors present the results of their findings in audit reports as well as in formal testimony and exhibits. When a utility requests a rate increase, cost-of-capital studies are performed to determine a recommended rate of return. Revenues, expenses and investments are analyzed to determine the amount needed for the utility to earn the recommended return on its investment. **Contact Terri Carlock, Utilities Division Deputy Administrator and Accounting Section Supervisor, (208) 334-0356.**

The Engineering Section of three engineers, two analysts and one supervisor reviews the physical operations of utilities. The staff of engineers and analysts develops computer models of utility operations and compares alternative costs to repair, replace and acquire facilities to serve utility customers. The group calculates and analyzes the price of acquiring cogeneration and renewable generation facilities and identifies the cost of serving various types of customers. They evaluate the adequacy of utility services and frequently help resolve customer complaints.
Contact Mike Louis, Engineering Section Supervisor, (208) 334-0316.

The Technical Analysis section of four utility analysts and one supervisor reviews utility Integrated Resource Plans, capital investments and forecasts of energy, water and natural gas use. They examine the prudency and cost-effectiveness of all Demand Side Management (DSM) programs , which include energy efficiency and demand response. They also identify potential for new DSM programs, track the impact on utility revenues and focus on residential self-generation.
Contact Stacey Donohue, Technical Analysis Section Supervisor, (208) 334-0363.

COMMISSION STAFF

The Telecommunications section includes two analysts who oversee tariff and price list filings, area code oversight, Universal Service, Lifeline and Telephone Relay Service. They assist and advise the commission on technical matters that include advanced services, 911 and other matters as requested.
Contact Carolee Hall, Telecommunications Analyst, (208) 334-0364.

The Consumer Assistance section includes five division investigators and one supervisor who resolve conflicts between utilities and their customers. Customers faced with service disconnections often seek help in negotiating payment arrangements. Consumer Assistance may mediate disputes over billing, deposits, line extensions and other service problems. Consumer Assistance monitors Idaho utilities to verify they are complying with commission orders and regulations. Investigators participate in general rate and policy cases when rate design and customer service issues are brought before the Commission.
Contact Beverly Barker, Consumer Assistance Administrator, (208) 334-0302.

Railroad Section

Our rail inspector oversees the safe operations of railroads that move freight throughout Idaho and enforces state and federal regulations safeguarding the transportation of hazardous materials by rail in the state. The Commission's rail safety specialist inspects railroad crossings and rail clearances for safety and maintenance deficiencies. The Rail section helps investigate all railroad-crossing accidents and makes recommendations for safety improvements to crossings.

As part of its regulatory authority, the commission evaluates the discontinuance and abandonment of railroad service in Idaho by conducting an independent evaluation of each case to determine whether the abandonment of a particular railroad line would adversely affect Idaho shippers and whether the line has any profit potential. Should the commission determine abandonment would be harmful to Idaho interests, it then represents the state before the federal Surface Transportation Board, which has authority to grant or deny line abandonments.
Contact Joe Leckie, Rail Section Manager, (208) 334-0331.

Pipeline Safety

The three-member Pipeline Safety section oversees the safe operation of the intrastate oil and natural gas pipelines in Idaho.

Pipeline safety personnel verify compliance with state and federal regulations by on-site inspections of intrastate pipeline distribution systems. Part of the inspection process includes a review of record-keeping practices and compliance with design, construction, operation, maintenance and drug/alcohol abuse regulations.

Key objectives of the program are to monitor accidents and violations, to identify their contributing factors and to implement practices to avoid accidents. All reportable accidents will be investigated and appropriate reports filed with the U.S. Department of Transportation in a timely manner.
Contact Joe Leckie, Pipeline Safety Program Manager, (208) 334-0331.

WHY CAN'T YOU JUST TELL THEM NO?

One of the most frequently asked questions the PUC receives after a utility files an application for a rate increase is, "Why can't you just tell them no?" Actually, we can, but not without evidence.

For more than 100 years, public utility regulation has been based on this regulatory compact between utilities and regulators: Regulated utilities agree to invest in the generation, transmission and distribution necessary to adequately and reliably serve all the customers in their assigned territories. In return for that promise to serve, utilities are guaranteed recovery of their prudently incurred expense along with an opportunity to earn a reasonable rate of return. The rate of return allowed must be high enough to attract investors for the utility's capital-intensive generation, transmission and distribution projects, but not so high as to be unreasonable for customers.

In setting rates, the Commission must consider the needs of both the utility and its customers. The Commission serves the public interest, not the popular will. It is not in customers' best interest, nor is it in the interest of the State of Idaho, to have utilities that do not have the generation, transmission and distribution infrastructure to be able to provide safe, adequate and reliable electrical, natural gas and water service. This is a critical, even life-saving, service for Idaho's citizens and essential to the state's economic development and prosperity.

Unlike unregulated businesses, utilities cannot cut back on service as costs increase. As demand for electricity, natural gas and water grows, utilities are statutorily required to meet that demand.

The Commission walks a fine line in balancing the needs of utilities to serve customers and customers' ability to pay.

When a rate case is filed, our staff of auditors, engineers, analysts and attorneys will take up to six months to examine the request. During that period, other parties, often representing customer groups, will "intervene" in the case for the purpose of conducting discovery, presenting evidence and cross-examining the company and other parties to the case. The Commission staff, which operates independently of the Commission, will also file its own comments that result from its investigation of the company's request. The three-member Commission will also conduct technical and public hearings.

Once testimony is presented from the company, commission staff and intervening parties, and testimony is taken from hearings and written comments, that information is included in the official record for the case. It is only from the evidence contained in this official record that the Commission can render a decision.

If the utility has met its burden of proof in demonstrating that the additional expense it incurred was 1) necessary to serve customers and 2) prudently incurred, the Commission must allow the utility to recover that expense. The Commission can — and often does — deny recovery of some or all the expense utilities seek to recover from customers if the Commission is confident it has the legal justification to do so. Utilities and parties to a rate case have the right to petition the Commission for reconsideration. If reconsideration is not granted, the Commission's decision can be appealed to the state Supreme Court.

2017 MAJOR EVENTS

Idaho gets second area code

Idaho's transition to a new area code and mandatory 10-digit dialing came to a close in September.

The process of introducing the state's second area code began in fall 2015, when the Commission approved a plan calling for mandatory 10-digit dialing in August 2017 and for providers to begin assigning the 986 area code to new customers in September 2017.

The need for Idaho's second area code was prompted by warnings that the state was on track to exhaust its supply of available telephone numbers by mid-2018.

The Commission had staved off the need for a new area code in 2001 by implementing various numbers conservation plans that successfully delayed the need by 15 years.

The demand for telephone numbers has increased significantly since then, however, due primarily to the proliferation of cell phones, the Internet, Voice over Internet Protocol and other emerging technologies.

The Commission decided in November 2015 that the state should assign the new area code statewide to all new phone numbers effective Sept. 5, 2017. Referred to as a "geographic overlay," this approach was one of two options for implementation of the new area code and was the unanimous recommendation of the state's telecommunications providers.

The other option, a "geographic split," would have assigned the new area code to all numbers in half of the state, requiring all customers in the area assigned the new area code to change their telephone numbers. That would have caused significant disruptions to businesses in the area with the new area code, the Commission determined.

While the "geographic overlay" option meant that everyone could keep their existing phone number, it also meant that Idahoans would have to dial 10 digits (area code plus prefix plus four digit number) for all calls within the state.

To ensure residents were prepared for this change, the Commission established a 16-month transition period highlighted by the introduction of voluntary 10-digit dialing in November 2016.

Ten-digit dialing became mandatory for all calls on Aug. 5, 2017, and providers began assigning the 986 area code on Sept. 5, 2017.

Commissioner Raper testifies before Congress regarding PURPA

Commissioner Kristine Raper spoke at a hearing before the House Energy and Commerce Committee's Subcommittee on Energy in September about the need to reform the Public Utility Regulatory Policies Act of 1978 (PURPA).

PURPA was intended in part to promote the development of renewable energy by requiring utilities to buy power from qualifying renewable facilities. While PURPA supporters say the law has helped spur

2017 MAJOR EVENTS

the development of wind and solar energy, critics contend developers of renewable energy are manipulating the law, resulting in higher electric rates.

Complaints in recent years prompted the House Energy and Commerce Subcommittee to review the law.

A series of hearings called "Powering America: Reevaluating PURPA's Objectives and Its Effects on Today's Consumers," were part of that review process.

In her testimony, Raper urged lawmakers to take steps to fix PURPA's flaws.

State regulators should have more authority to determine what constitutes a qualifying facility under the law, Raper testified. Today that responsibility is exclusively under the jurisdiction of the Federal Energy Regulatory Commission.

Avista Utilities proposes merger with HydroOne

In September, Avista requested regulatory approval of its proposed merger with HydroOne Limited, which provides electric service to more than 1.3 million customers in Ontario.

The Commission is one of several regulatory entities that must approve the $5.3 billion deal. Others include regulatory agencies in Washington state, Oregon, Montana and Alaska, and the Federal Energy Regulatory Commission.

The merger also must comply with the Hart-Scott-Rodino Antitrust Improvements Act of 1976, and it must be authorized by the Committee on Foreign Investment in the United States, an inter-agency governmental board charged with reviewing the national security implications of foreign investments in US companies.

If the merger is approved, Avista would become a wholly-owned subsidiary of HydroOne but would keep its name and continue to operate out of its current headquarters in Spokane as a "standalone utility" with its existing employees and management team.

Combined, the two companies would be one of the largest regulated utilities in North America, with more than $25.4 billion in assets.

In its application requesting Commission approval, Avista said its customers would see immediate benefits of receiving service from a larger utility, including a proposed rate credit of $31.5 million that would be distributed over a 10-year period.

Long-term benefits of the merger include increased purchasing power and reduced costs associated with efficiencies that emerge as best practices and business processes are developed and technology shared, according to the company.

Based in Toronto, HydroOne is the largest electric utility in Ontario. It lacks generation resources but maintains a network of nearly 19,000 miles of transmission lines and 77,000 miles of distribution lines.

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Avista's generation resources include eight hydropower facilities, five natural gas plants and a biomass facility. The company has ownership interest in two coal-fired plants and maintains more than 20,800 miles of transmission and distribution lines. It provides electric service to approximately 130,000 Idahoans and natural gas service to more than 80,000 in northern Idaho.

The Commission will analyze the proposed merger in order to determine whether it is in the interest of Idaho residents. Idaho Code 61-328 states that an electric utility may transfer property only if the Commission finds that:

- Rates will not increase because of the transaction.
- The buyer has the intent and financial ability to operate and maintain the property in the public service.
- The transaction is consistent with the public interest.

The Ontario government owns 49.9 percent of HydroOne's shares but "it does not hold or exercise any managerial oversight over Hydro One," according to the application.

If the merger is approved, Avista would no longer be a publicly-traded company and would instead have one owner, HydroOne.

The companies have requested Commission approval of the merger by mid-August 2018.

Intermountain Gas' first rate case in more than 30 years is resolved

In April, the Commission approved a rate increase for Intermountain Gas customers, the company's first general rate case since 1985.

The Commission's 46-page order called for a 1.58-percent increase effective May 1.

The company's proposal had called for rates to increase by an average of 4.06 percent but was revised to an average 3.7-percent increase after a three-day technical hearing.

The Commission's decision also called for the elimination of seasonal rates for residential customers, adoption of a demand charge for two customer classes – large volume and transportation, and acceptance of Intermountain's proposal to create demand side management programs to help customers reduce natural gas consumption in order to decrease the amount of gas the company would have to buy from wholesale suppliers.

Intermountain petitioned the Commission to reconsider its decision on May 18, citing four concerns.

Two of Intermountain's concerns pertained to weather data used to project energy usage, and therefore revenue. In its order, the Commission found that Intermountain Gas' methodology for using weather data to forecast energy usage among its customers was not reproducible.

That made it impossible to determine whether the company's model accurately projected the amount of energy it would need to purchase, and the amount of revenue required to recover those expenses

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through customer rates, the Commission said. As a result, the Commission used a weather normalization model developed specifically for this case and decreased the associated revenue requirement by approximately $2 million.

Intermountain's reconsideration petition said the Commission's analysis overstated revenue.

The utility also expressed concern with the Commission's decisions to disallow $1.38 million in expenses paid to Intermountain's affiliate, MDU Resources, and $704,000 in nonexecutive incentive compensation.

In granting Intermountain's reconsideration petition, the Commission directed the interested parties to explore settlement opportunities. The parties, which included the company, commission staff and the Northwest Industrial Gas Users, forged a settlement agreement in September that called for a compromise on the four concerns that Intermountain had cited.

The settlement approved by the Commission allowed the company to recover an additional $1.2 million in expenses related to affiliated expenses and incentive compensation, representing a 50/50 split of the dollar amounts related to these two issues, and to recover an additional $6,065 in annual base rate revenues related to weather modeling. The settlement also establishes a procedure for determining the weather normalization methodology employed in future rate cases.

The settlement agreement resulted in a 1.36-percent rate increase across all customer classes. That equates to an additional 37 cents on the monthly bill of the average residential customer.

IPUC rules on Idaho Power preparations for entry into Energy Imbalance Market

In February, the Commission approved Idaho Power's request to authorize a deferral account to track the costs incurred associated with joining the California ISO's Energy Imbalance Market (EIM).

The Commission believed it was premature to find that the utility's participation would benefit customers in the long term, however.

The EIM that Idaho Power plans to join in April 2018 balances the supply and demand for energy via automated dispatch services at five-minute intervals from generation resources across the region.

Idaho Power's current configuration features hourly dispatch services from its own generation and reserve resources.

Idaho Power contends that moving from an hourly market to a five-minute imbalance market will allow it to balance supply and demand more efficiently and cost-effectively.

The potential annual savings could be between $4 million and $5 million, Idaho Power said; the upfront costs of joining the EIM were estimated at approximately $11 million.

The Commission adopted Idaho Power's proposal to spread the initial costs over a 10-year period but

2017 MAJOR EVENTS

said the costs cannot be recovered from ratepayers until they are known rather than estimated. Those costs also must be found to be prudently incurred before they are included in rates.

In its order, the Commission also asked the company to provide more evidence of customer benefits.

Idaho Power had proposed providing a quarterly benefits report provided by the EIM administrator, the California Independent System Operator. The Commission asked for such a report but further directed the company to provide a report one year after joining the EIM that outlines the costs and benefits of participation.

Commission approves settlement related to early closure of coal plant

In June , the Commission approved a settlement related to the early retirement of a coal-fired plant in Nevada.

The settlement allows the company to accelerate the recovery of its investment in the North Valmy Power Plant through base rates, leading to a rate increase of 1.17 percent.

That equates to an additional $1.20 on the monthly bill of the typical residential customer using 1,000 kilowatt-hours (kWh) per month.

The company had originally proposed raising rates by 3.1 percent to recover its investment in Valmy. That would have led to a $3.08 increase to the monthly bill of the typical residential customer using 1,000 kWh per month.

The settlement agreement calls for shuttering Valmy's Unit 1 in 2019, and Unit 2 in 2025.

Unit 1 went into service in 1981 and Unit 2 came online in 1985. Each had a 50-year life expectancy, and their depreciation was embedded in Idaho Power's base rates with the expectation that the units would operate until 2031 and 2035, respectively.

The rate increase is expected to generate nearly $13.3 million in annual revenue until 2028, when Valmy is fully depreciated – down from $28.5 million in Idaho Power's original proposal.

Idaho Power maintains that closing the plant early will ultimately save customers money. The company said a significant decrease in market prices for electricity had made it uneconomic to operate the 522-megawatt plant except during extremely cold or hot weather, when the demand for energy surges.

Idaho Power said costs associated with the plant's operation have increased significantly since 2011.

ELECTRICAL POWER IN IDAHO

Avista Utilities

2016 average number of customers/average revenue per kilowatt-hour

330,699 residential customers/$0.09605

41,785 commercial customers/$0.09613

1,342 industrial customers/$0.06085

Idaho Power Company

2016 average number of customers/average revenue per kilowatt-hour

440,362 residential customers/$0.1029

88,561 commercial customers/$0.0772

121 industrial customers/$0.0563

Rocky Mountain Power

2016 average number of customers/average revenue per kilowatt-hour

62,615 residential customers/$0.1064

9,339 commercial customers/$0.0910

628 industrial customers/$0.0658

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Settlement reached in Avista rate case

Avista's electric rates increased by an average of 2.6 percent on Jan. 1, 2017 after the utility reached a settlement with Commission staff and other parties.

The company had originally requested a 6.3-percent increase. The most significant adjustment to the company's proposal was to move $4.5 million in net expenses for the Palouse Wind project from base rates to the annual Power Cost Adjustment process.

The move reduced the economic burden imposed on Idaho ratepayers by 10 percent. The settlement also set the residential basic charge at $5.75 per month, down from $6.25 the company had requested.

In June 2017, Avista asked for approval of a two-year plan calling for rate increases in 2018 and 2019.

The company said the request was driven by ongoing investments in its plants and technology in addition to increased costs of providing power to its customers.

A tentative settlement agreement was reached in late September. If approved by the Commission, the settlement would increase electric rates by an average of 5.6 percent in 2018 and 2.3 percent in 2019, while increasing the basic monthly service charge by 25 cents, to $6. The company's original proposal called for an average increase of 7.9 percent in 2018 and 4.2 percent in 2019, along with the 25-cent increase to the service charge.

Commission deems prudent Avista's energy efficiency expenses

In June, the Commission determined that nearly $10 million Avista spent on energy efficiency programs in 2014 and 2015 was prudently incurred and therefore could be recovered through an energy efficiency rider paid by the 125,000 northern Idahoans who receive electric service from Avista.

The programs, which include educational outreach and incentives for weatherization measures, saved 31,081 megawatt-hours (MWh) over the two-year period, just meeting the company's goal of 30,996 MWh.

Commission approves changes to several surcharges

The Commission approved modifications to four annual billing mechanisms in September that affect customers who receive electric service from Avista.

The changes took effect Oct. 1, and the overall impact to residential customers was a 2-percent increase, or $1.73 on the monthly bill of the average residential customer using 910 kWh per month.

Here's a look at those billing mechanisms:

Fixed Cost Adjustment

This mechanism is modified annually in order to allow a utility to recover any fixed costs that are lost when energy sales decline. It is intended to remove a utility's disincentive to promote energy efficiency

ELECTRIC CASES

and conservation by ensuring that the utility will recover its fixed costs even if energy sales decline. In requesting Commission approval to increase the FCA by 3 percent, the maximum allowed, Avista said revenue fell short of expenses by approximately $6.5 million in 2016 due to an abnormally warm winter as well as savings from its energy efficiency programs.

As a result of the change, a residential customer using an average of 910 kWh in a month would see an increase of $2.56 on the monthly bill.

Power Cost Adjustment

This mechanism allows Avista to modify its rates annually when its costs of generating and purchasing electricity to serve is customers do not equal the revenue recovered through rates.

Since power supply costs were lower than expected in 2016, the PCA approved in September is expected to refund customers approximately $7.3 million.

That equates to a decrease of $2.03 on the monthly bill of the average residential customer using 910 kilowatt-hours per month.

Residential and Small Farm Energy Credit

The result of an agreement between the utility and the Bonneville Power Administration, this credit passed through to customers the benefits of the federal Columbia River hydropower system.

The change approved in September lowered the bill of the average residential and small farm customer by 0.2 percent. That equates to a savings of 16 cents on the monthly bill of the average residential customer using 910 kWh.

Energy efficiency rider

In September 2017, the Commission approved an increase to the Energy Efficiency Rider for Avista's electric customers.

The change took effect Oct .1, leading to an increase of $1.37 on the monthly bill for a residential customer using 910 kWh.

Adjusted with Commission approval, this surcharge allows a utility to recover the costs incurred providing energy efficiency services to its customers, and to match future revenue with expenses budgeted for energy efficiency programs.

In 2016, Avista's energy efficiency programs were underfunded by nearly $10 million. The primary reason for the deficit was a non-residential lighting program that exceeded its budget by $9 million.

The increase approved by the Commission is expected to boost revenue by approximately $3.9 million annually.

The surcharge is now assessed at 0.395 cents per kilowatt-hour used for residential service, up from 0.245 cents per kWh, while the surcharge will increase to 0.427 cents per kWh for general service customers, up from 0.271 cents per kWh.

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Programs funded by the rider will be scrutinized for prudency in a future proceeding. Expenses incurred through the programs must be cost-effective in order for the costs to be recovered through customer funds. Expenses not found to be prudent must be paid by shareholders rather than customers.

Avista files long-range planning document with IPUC

Avista expects conservation measures to offset more than half of its expected load growth over the next 20 years, according to a planning document filed with the Commission in August.

Though the need for new generation is expected, Avista's Integrated Resource Plan (IRP) also indicates its current generation resources will remain cost effective and reliable through 2036.

Regulated utilities are required to file an updated IRP with the Idaho Public Utilities Commission every other year. The IRP serves as a status report on a utility's ongoing plans to serve customers at the lowest cost and least risk over the next two decades.

Avista's 2017 IRP differs from its 2015 plan in several ways, including the anticipation of a slowdown in the annual growth rate, from 0.6 percent projected in the 2015 IRP to 0.47 percent; less reliance on natural gas-fired peaker plants; and a delay in the need for additional generation from 2020 until 2026.

The delay is due not only to lower than expected load growth but also recently signed contracts for hydropower, energy efficiency measures and the introduction of demand response programs that temporarily reduce the demand for energy.

While the preferred strategy outlined in Avista's 2015 IRP called for 557 megawatts (MW) of new natural gas generation, with the first facility projected to be in service by the end of 2020, the 2017 IRP calls for three new natural gas-fired plants with a combined capacity of 353 MW.

Those consist of a 204 MW natural gas-fired peaker plant to begin operation in 2026, a 102 MW peaker plant by the end of 2030 and a 47 MW peaker plant in 2034.

Peaker plants derive their name from the fact that they are utilized only during periods of peak demand for energy among customers. According to Avista, these peaker plants are more cost-effective because they provide a low-cost, flexible source for generation that allows the utility to efficiently incorporate intermittent power generation, such as wind and solar.

The company also plans to construct a 15 MW solar facility for its commercial and industrial customers, and is building two energy storage facilities that would provide a total of 2.5 MWh of storage.

Most of Avista's generation is through hydropower. The company owns and operates eight hydropower plants capable of generating 1,080 MW. The IRP calls for improvements to those plants that would boost capacity throughout the planning period.

Avista also recently signed long-term contracts with public utility districts to purchase hydropower gen-

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erated on the Columbia River. These contracts are capable of adding 165.3 MW to Avista's system. The company's thermal generation consists of five natural gas plants, a biomass facility and a 222-MW share of the output at the Colstrip coal plant. The Colstrip plant consists of four units located east of Billings, Montana.

Avista owns 15 percent of Units 3 and 4, which began operating in 1984 and 1986, respectively. Units 1 and 2 went into operation in the mid-1970s and are set for retirement by 2022. Avista said it analyzed a number of scenarios for Colstrip Units 3 and 4, including early retirement and significant reductions in generation.

But its preferred strategy calls for the two units to remain in service through the end of the planning period, as it remains a cost-effective and reliable source of power.

Avista's conservation efforts are expected to help meet 53.3 percent of the growth in load over the next 20 years. Current conservation efforts reduce retail loads by more than 12 percent. The IRP evaluated more than 8,700 options to reduce energy use.

These conservation and efficiency programs outlined in the IRP target not only customer consumption but also Avista operations. Plans call for upgrades to distribution equipment throughout its service area, as well as upgrades to boost efficiencies at Avista facilities. Overall, the company said it has identified 15,370 MWh of "achievable potential conservation" in Idaho.

Commission grants CPCN for transmission line in Wood River Valley

In September the Commission approved Idaho Power's application for a Certificate of Public Convenience and Necessity (CPCN) to build a new transmission line to serve the Wood River Valley.

In granting the request, the Idaho Public Utilities Commission said Idaho Power demonstrated that a redundant line is necessary to mitigate the risk to public health and safety of the valley's 9,000 residents.

The Wood River Valley is currently served by two substations fed by a single transmission line that links substations near Hailey and Ketchum. The need for a redundant transmission line in the valley was identified in the mid-1970s, and a previous CPCN was canceled in 1995 at the company's request.

The existing line was built in 1962 on wooden poles in mountainous terrain that can be difficult to access. It needs to be rebuilt, Idaho Power said, and a redundant line would also allow the line to be rebuilt without planned power outages.

In its CPCN application, Idaho Power said structure failure along the line could lead to an extended power outage. A redundant line would eliminate that risk, the company said.

In weighing the evidence, the Commission was persuaded that a major outage could last days or weeks due to access limitations along the current line that would hamper repair efforts.

Granting the CPCN is not a mandate to build the new line. In fact, the Commission's 18-page order notes that while Idaho Code requires a public utility to obtain a CPCN before constructing certain facili-

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ties or infrastructure, a CPCN is not required to extend lines, plant or system in an area already served by a utility.

The order also does not constitute approval of the cost of the project for ratemaking purposes.

Idaho Power is required to apply to the Commission in order to recover expenses associated with the project from its customers.

The project is expected to cost $30 million, with the company's proposed route calling for a transition from overhead lines to underground lines for a portion of the route leading into Ketchum.

IPUC approves Idaho Power proposal to lower efficiency surcharge

In April, the Commission approved an Idaho Power request to lower the energy efficiency rider paid by customers to fund conservation and efficiency programs. The move to lower the rider from 4 percent of monthly billed amounts to 3.75 percent led to a 22-cent decrease on the monthly bill of the average residential customer who uses 1,000 kWh per month.

The Commission also approved the company's request to refund customers $13 million in rider funds on June 1, reducing the impact of an increase to the Purchased Cost Adjustment billing mechanism.

Battery storage facilities eligible for contracts with Idaho Power

In July, the Commission determined that five proposed battery storage facilities were eligible for two-year, negotiated contracts with Idaho Power.

Plans call for the batteries to be charged with energy from nearby solar projects capable of generating 2.5 average megawatts, with the electricity dispatched to Idaho Power under the provisions of the Public Utility Regulatory Policies Act (PURPA).

PURPA requires electric utilities to purchase energy from qualifying independent power producers but gives state regulators authority to determine the contract terms for PURPA-eligible facilities.

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In Idaho, PURPA projects larger than 100 kilowatts and powered by intermittent sources such as solar and wind are eligible for two-year contracts at a rate negotiated between the utility and the developer (IRP methodology).

The developer, Franklin Energy, contended that its storage projects should qualify for 20-year contracts at the more favorable published rate set by the Commission.

Franklin petitioned the Commission to reconsider its decision. In denying the request to reverse its decision, the Commission said Franklin failed to show that the final order was "unreasonable, unlawful, erroneous or not in conformity with the law."

Commission approves modifications to billing mechanisms

In May, the Commission approved several cost adjustments for Idaho Power Company, leading to a rate increase of almost $2 on monthly bills of a typical residential customer as of June 1.

The Power Cost Adjustment increased by an average of 0.93 percent, leading to a 59-cent increase

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on the monthly bill for Idaho Power's typical residential customer using 1,000 kilowatt-hours., while a 1.29-percent increase to the Fixed Cost Adjustment led to an average monthly increase of $1.31.

The FCA is adjusted annually based on changes in energy use during the previous year by customers in two classes, Residential and Small General Service.

The mechanism separates revenues and energy sales, enabling the company to recover fixed costs incurred delivering energy to its Idaho customers even if energy sales decrease.

Without the FCA, the company would have a disincentive to help customers use less energy, or use it more efficiently, since there would be a loss of revenue as energy use declined.

In 2016, the company's residential energy sales decreased by 245,027 megawatt-hours (MWh) from 2015 levels, due in part to the growth of its energy efficiency programs.

That decrease in energy sales, combined with an increase in the number of customers in the Residential and Small General Service customer classes, left the company unable to recover its fixed costs for the year.

The FCA is now assessed at .6728 cents per kilowatt-hour (kWh) for Residential customers and .8576 cents per kWh for customers in the Small General Service class. The increase is projected to boost revenue by approximately $6.96 million, matching the amount under-collected in 2016.

The PCA allows Idaho Power to modify its rates each year to contend with fluctuations in the cost of serving customers due to factors beyond its control. Those factors include market prices for power, power transmission costs, revenue earned from selling surplus power and stream flows that diminish the hydropower generation on which the company relies.

The PCA is examined annually and adjusted up or down to either pay down already-incurred expenses if power costs exceed forecasts, or credit customers when expenses fall short.

The company said last year's power costs exceeded forecasts due in part to worse-than-expected water conditions. While stream flows have improved for 2017, the company expects to incur greater costs associated with solar and wind generation, and the unexpected collapse and abandonment of the Joy Longwall by the Bridger Coal Company.

As a result, the Commission approved raising the surcharge to .7361 cents per kWh, from .6187 cents.

Idaho Power seeks prudency determination for relicensing effort

In late 2016, Idaho Power asked the Commission to find that it had prudently incurred approximately $221 million in expenses related to a years-long effort to relicense the Hells Canyon Complex, the utility's largest hydropower facility. The company's application asks the Commission to deem those expenses prudently incurred and eligible for inclusion in customer rates in the future.

The Hells Canyon Complex provides more than one-third of the company's total generating capacity. Its license with the Federal Energy Regulatory Commission expired in 2005 and the company has been

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operating under an annual license issued by FERC since then. The relicensing effort began in 1991, according to the company, which led to filing for a new license in 2003. It estimates a new 40- or 50-year license will be issued after 2021.

Idaho Power proposal would reclassify net metering customers

In July, Idaho Power asked the Commission to approve its plan to overhaul its treatment of customers with on-site generation systems such as rooftop solar.

Idaho Power customers who generate their own electricity are currently included in the same rate class as traditional electric customers.

Since net metering customers can offset their energy consumption via their on-site generation resources, Idaho Power contends they do not pay their fair share for the operation and maintenance of the company's electric distribution system.

This shifts the financial burden of maintaining and running that system onto Idaho Power's traditional customers, creating a "wealth transfer from lower-income customers to higher-income customers," the company's filing states.

The company's proposed solution is to separate net metering customers into two distinct customer classes, Residential and Small General Service. The company said this would allow it to better understand those customers' impact on the distribution system.

The proposal applies to customers with on-site generation who sign up for new service on or after Jan. 1, 2018, existing net metering customers would "transition over some period of years" to one of the proposed new customer classes.

Idaho Power's proposal does not call for any changes to rates. Any such changes would be addressed in a future rate case.

Rocky Mountain Power submits plan for Commission acceptance

Rocky Mountain Power expects to transition away from coal over the next 20 years, according to the utility's Integrated Resource Plan (IRP).

The IRP outlines the utility's strategy for meeting customer demand for electricity through 2036.

It calls for the retirement of more than 3,500 megawatts of coal-fired generation, and for that generation to be replaced primarily with renewables such as wind and solar.

Efficiency measures, wholesale power purchases and two new natural gas facilities are also expected to help meet the demand for energy through 2036.

The Commission's acknowledgement of the IRP does not necessarily mean the projects highlighted will be completed, but rather that the utility has met its long-range planning requirements.

The first new natural gas-fired resource is expected to be added in 2029, a year later than anticipated in the utility's previous IRP, filed in 2015.

ELECTRIC CASES

The utility expects incremental energy-efficiency resources to provide a 2,077 MW reduction - enough to meet 88 percent of the forecasted load growth through 2026. The 2017 plan does not call for upgrades to coal plants in order to meet environmental regulations, a decision that will "save customers hundreds of millions of dollars," according to the company.

Instead, the IRP calls for 3,650 MW of existing coal capacity to be retired by the end of 2037.

The company expects to offset a portion of that lost generation with market purchases, although Rocky Mountain intends to construct two new natural gas facilities – a 200-MW frame simple cycle combustion turbine in 2029, and a 436-MW combined combustion turbine in 2030.

Over the life of the IRP, the preferred portfolio includes 1,313 MW of new natural-gas capacity. That is a reduction of 1,540 MW relative to the 2015 IRP.

Rocky Mountain seeks approval for wind and transmission projects

In July, Rocky Mountain Power asked the Commission to approve its plans to build or acquire four wind farms in Wyoming, upgrade or "repower" 13 existing wind facilities and improve its transmission system.

The projects are expected to cost $3.13 billion and would significantly boost the utility's capacity to generate wind energy.

Rocky Mountain Power asserted that the transmission projects are necessary in order to relieve congestion on the transmission system and improve the utility's ability to manage the intermittent load produced by wind.

Rocky Mountain requested that the Commission allow the projects' capital costs to be incorporated into customer rates, and for approval of Certificates of Public Convenience and Necessity (CPCN) for the new wind facilities and transmission improvements.

Rocky Mountain Power also asked the Commission to expedite the approval process to ensure that the projects meet deadlines for federal renewable electricity production tax credits. The wind projects must be in operation by the end of 2020 in order to achieve the full benefit of the production tax credits.

The projects are pending before the Commission in two cases.

One is the $1.13 billion wind repowering project and the other is the $2 billion project that calls for construction of the four wind facilities and the construction of or improvements to several transmission facilities in eastern Wyoming.

A tentative settlement agreement has been reached in the wind repowering case. The company's proposal calls for repowering, or upgrading, eight wind projects in Wyoming, four in Washington state and one in Oregon.

The facilities now represent 999.1 megawatts (MW) of installed capacity, and the project is expected to increase generation between 11 and 35 percent. Upgrades would include installation of higher-

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capacity generators and rotors with longer blades, which produce more energy at lower wind speeds.

In addition to increased energy output, the project's benefits would include greater control of power quality and voltage, which would allow the utility to more efficiently integrate wind energy into its transmission system and enhance the reliability of the electric grid, Rocky Mountain Power said.

The company also noted that the project's benefits can be achieved without the costs and complexity of permitting and constructing new facilities, while extending the facilities' useful life and cutting operating costs.

Rocky Mountain Power asked the Commission to issue its decision on the proposal by Dec. 29 in order to receive the full benefit of the production tax credits.

The current tax credit is $24 per megawatt-hour. That amount is adjusted annually but expires 10 years after a facility goes into service.

The tax credits for most of the facilities proposed for repowering are set to expire in 2018 and 2019. Overall, the company said, the repowering projects would lead to customer savings of between $41 million to $589 million, with natural gas prices and federal regulations representing the biggest variables.

The economic benefits are derived by a number of factors, including increased energy output, reduced operating costs, extended operational life, requalification for the production tax credits and the sale of renewable-energy credits.

Capital expenses related to the project would be assessed on customer rates through the Energy Cost Adjustment Mechanism, which can be adjusted up or down annually depending on costs incurred, and benefits reaped, by the company.

Rocky Mountain's $2 billion proposal requests Commission approval for CPCNs for four Wyoming wind projects with a combined capacity of 860 MW. Three have a capacity of 250 MW and one is capable of generating 110 MW.

The proposal also includes the construction of or improvements to several transmission facilities in eastern Wyoming. Most of the improvements are associated with the company's Energy Gateway West transmission project, which calls for the addition of approximately 2,000 miles of transmission lines in order to alleviate congestion on the transmission system, address growth and incorporate new generation sources such as wind.

The projects are mutually dependent, according to the company: The wind projects are not economic without the transmission projects, and the transmission projects are not economic without the wind resources.

The $2 billion cost estimate would lead to a rate increase of less than 1.9 percent in 2021, which is

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expected to be the first full year of operation of the new facilities, according to the company.

However, Rocky Mountain Power said the work is expected to save $137 million in avoided costs through 2050, when the wind projects are fully depreciated.

RMP proposal would lower wind integration rate, set solar rate

In August, Rocky Mountain Power requested approval to significantly lower the rate it charges to integrate wind energy into its system.

The company's proposal calls for lowering the integration rate from $3.06 per megawatt-hour (MWh) to 57 cents per MWh, and setting the rate for the purchase of solar energy at 60 cents per MWh.

The rates would apply to facilities that qualify for 20-year contracts under the Public Utility Regulatory Policies Act (PURPA). The law requires regulated utilities to purchase energy from qualifying independent power producers at rates established by state commissions.

In Idaho, facilities smaller than 100 kilowatts that are powered by intermittent sources such as wind and solar are eligible for 20-year contracts at the published rate set by the Idaho Public Utilities Commission.

The rate is referred to as the avoided-cost rate because it is intended that it not be higher than the rate at which the utility could generate the power on its own, or the rate at which the utility could purchase the energy elsewhere.

The integration rate for solar and wind facilities that qualify for power purchase agreements under PURPA is deducted from the avoided-cost rate paid by the utility.

In its proposal, Rocky Mountain said its analysis had found that the costs of wind energy and its integration had fallen significantly since the current integration rate was set in 2008.

Commission approves decrease to surcharge to reflect lower costs

In May the Commission approved a decrease to the Energy Cost Adjustment Mechanism to reflect a drop in power supply costs.

The ECAM allows the utility to adjust its rates each spring to account for expenses tied to the previous year's power purchases and sales. It appears on customer bills as a separate line item that increases if those costs are higher than the revenue generated through base rates. The ECAM surcharge decreases if the power supply costs are lower than the revenue generated through base rates.

Rocky Mountain said its power supply costs in 2016 were approximately $7.53 million lower than projected, primarily due to a decline in natural gas prices.

The change to the ECAM took effect June 1 and led to a decrease of 0.8 percent for residential customers, or about 73 cents per month for a typical residential customer who uses 800 kilowatt-hours of electricity. It is now assessed at .4958 cents for each kilowatt-hour used.

ELECTRIC CASES

Commission approves change to federal rate credit

In the fall the Commission approved a change to a federal rate credit that led to a slight decrease in the power bills of Rocky Mountain customers.

The change to the Residential and Small Farm Energy Credit took effect Oct. 1 and lowered the bill of the average residential customer by $6.60 – or 51 cents more than the current credit, which expired Sept. 30.

The credit is the result of an agreement between the company and the Bonneville Power Administration (BPA) that passes through to customers the benefits of the federal Columbia River hydropower system.

BPA markets and distributes the wholesale power generated through the system, which consists of 31 federal hydroelectric projects on the Columbia and Snake rivers.

While customers of publicly owned utilities (rural co-ops, for example) have preferential access to BPA power, the Northwest Power Act of 1980 requires that customers of private, investor-owned utilities also share in the benefits of the federal hydro projects through a rate credit as part of BPA's Residential Exchange Program.

NATURAL GAS

Consumption increased and prices declined in FY2017

In Idaho, natural gas is supplied to customers by Avista Utilities, Dominion Questar Gas and Intermountain Gas Company.

Idaho is fortunate to be located between two large natural gas storage basins: The Rocky Mountain Basin (Rockies) and the Western Canadian Sedimentary Basin (WCSB).

These basins are connected through the Williams Northwest Pipeline and the TransCanada Gas Transmission Northwest pipelines allowing the utility companies serving Idaho to take advantage of capacity and of pricing at both basins.

FY 2017 Statistics	Total	Residential	Commercial	Industrial	Transportation
Intermountain Gas					
Customers	346,894	314,444	32,330	19	101
% of Total	100%	90.65%	9.32%	0.01%	0.03%
Therms (millions)	783	247	129	8	399
% of Total	100%	31.53%	16.48%	1.03%	50.96%
Revenue (millions)	$277.60	$178.97	$83.58	$3.43	$11.57
% of Total	100%	64.48%	30.11%	1.24%	4.17%
Avista Utilities					
Customers	80,915	72,000	8,812	95	8
% of Total	100%	88.98%	10.89%	0.12%	0.01%
Therms (millions)	145.60	52.54	30.79	2.49	59.78
% of Total	100%	36.09%	21.15%	1.71%	41.06%
Revenue (millions)	$67.6	$45.25	$20.43	$1.35	$0.54
% of Total	100%	66.97%	30.24%	2.00%	0.80%
Dominion Questar Gas					
Customers	2,160	1,910	250	0	0
% of Total	100%	88.43%	11.57%	N/A	N/A
Therms (millions)	2.41	1.36	1.05	N/A	N/A
% of Total	100%	56.50%	43.50%	N/A	N/A
Revenue (millions)	$1.91	$1.17	$0.74	N/A	N/A
% of Total	100%	61.34%	38.66%	N/A	N/A

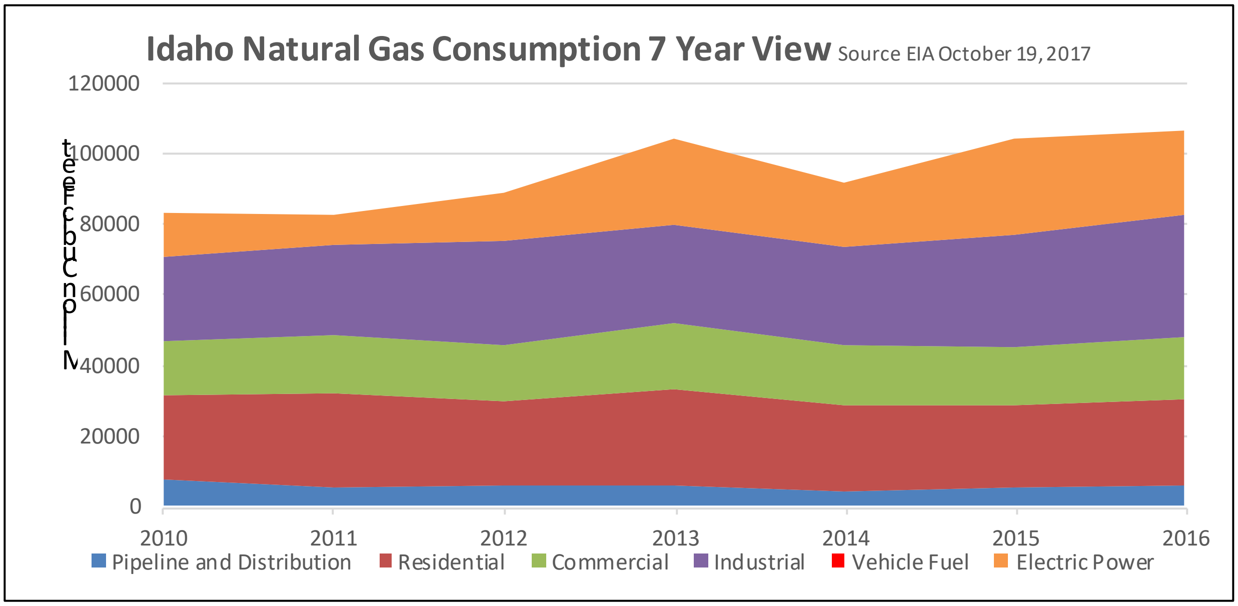
Transportation is nonutility owned gas transported for another party under contractual agreement.

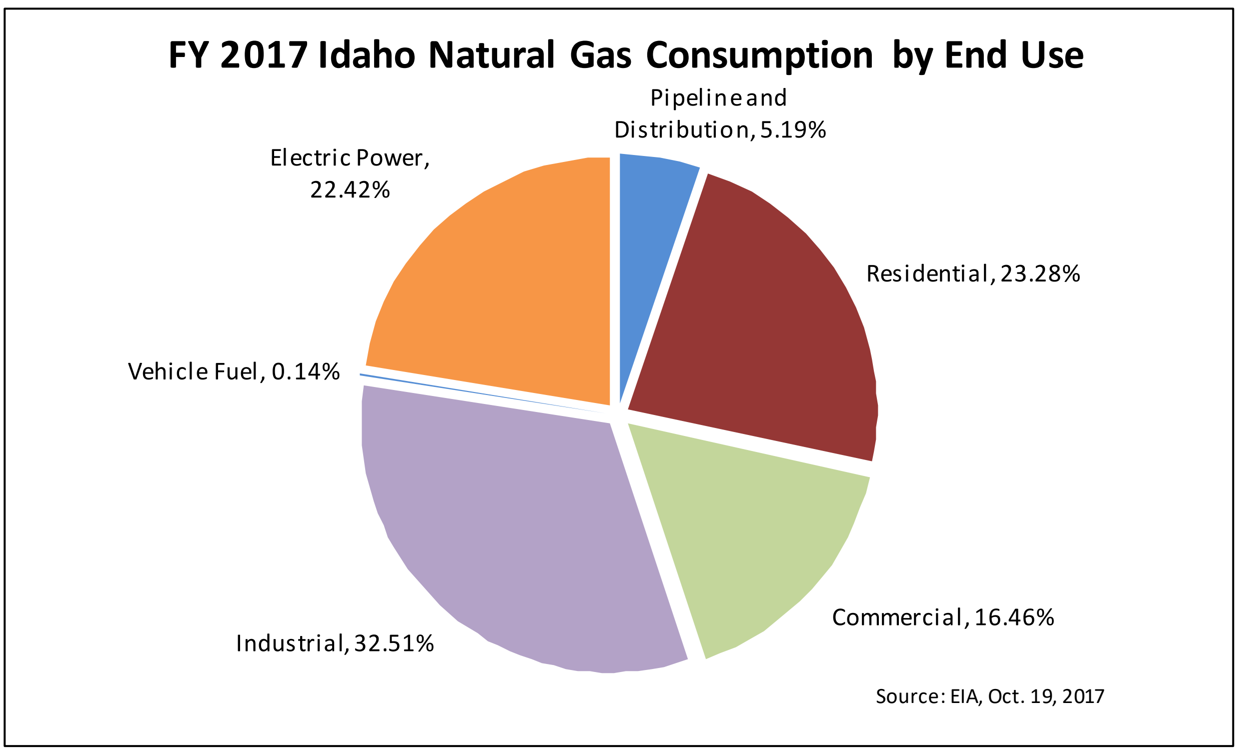
NATURAL GAS

Individual Idaho Gas Utility Profiles

Consumption

Overall consumption of natural gas in Idaho increased 2.1 percent during the fiscal year. All segments consumed more natural gas than the previous year with the exception of gas for electric generation, which declined approximately 13.5 percent.





NATURAL GAS

Demand

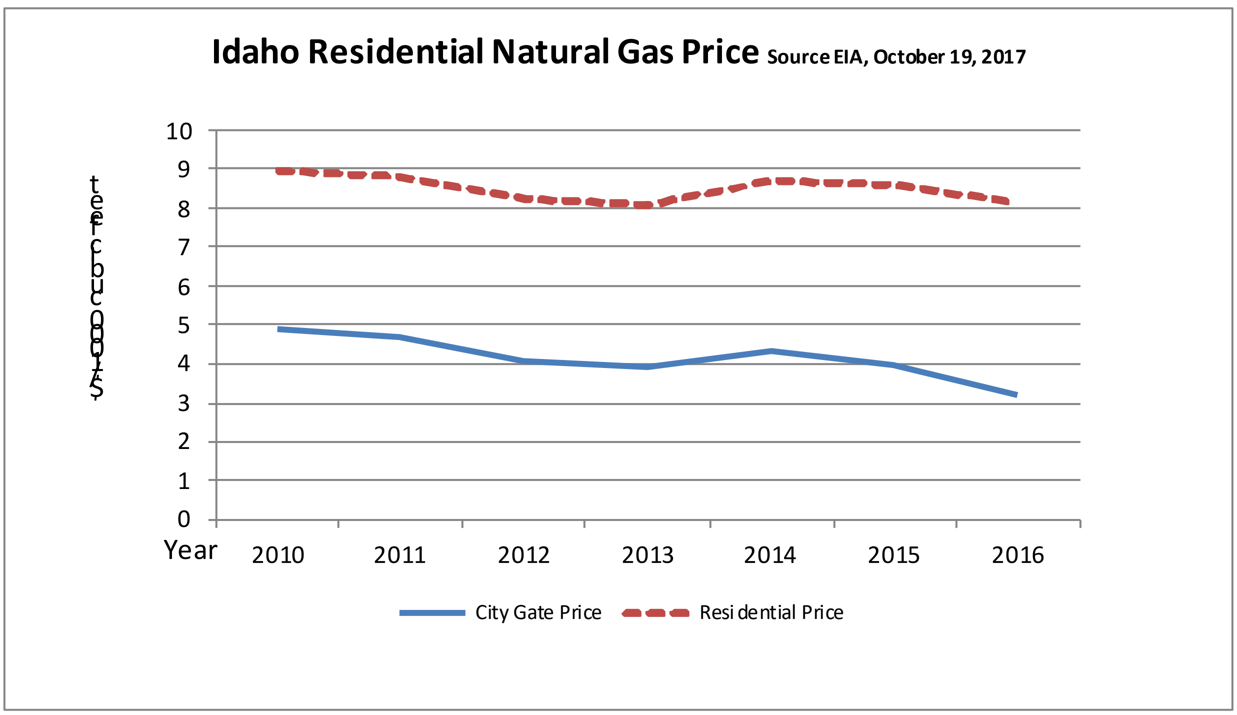
The Northwest Gas Association (NWGA) forecasts demand for natural gas in the Northwest to grow at a Compound Annual Growth Rate (CAGR) of approximately 0.8% per year over the next 10 years.

A number of factors could impact demand for natural gas:

- Pricing
- Natural gas used for generating electricity
- Significant incremental industrial loads
- The potential for natural gas as a transportation fuel
- LNG and petrochemical production and exports
- Energy policies, regulations and legislation

Prices

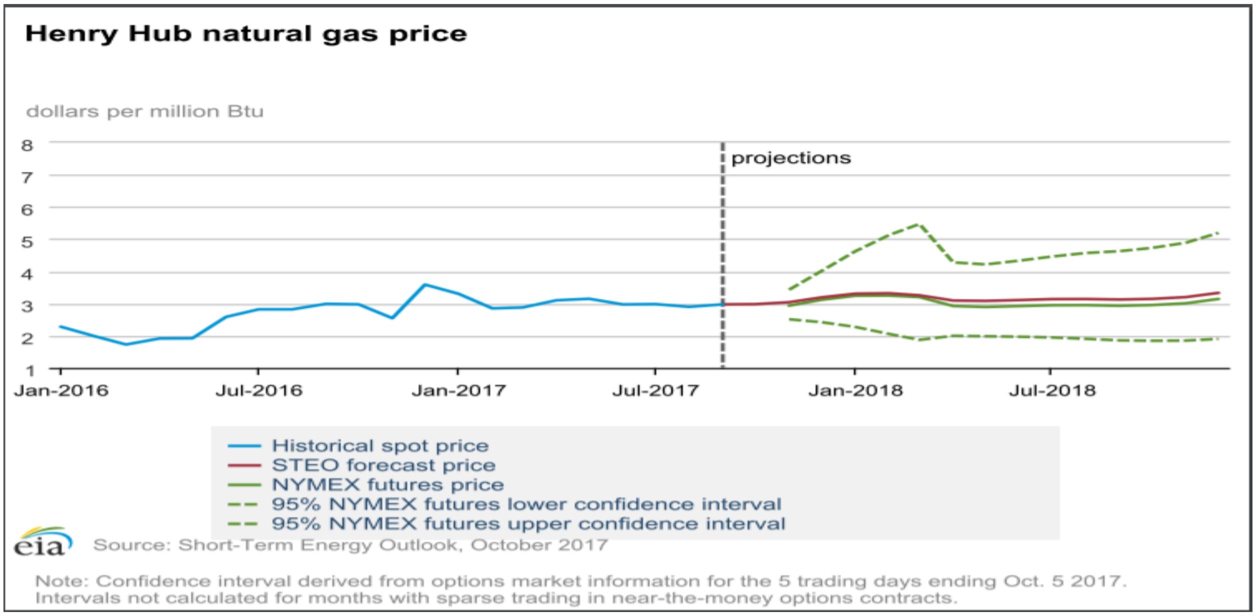
Recently, prices at the Henry Hub have been hovering near $3.00/MMBtu and are anticipated to remain close to this level in 2017. Prices in 2018 are expected to increase slightly over 2017.



Natural gas spot prices are projected to increase in 2018 to an average of $3.19/Dth (dekatherm*), at the Henry Hub.

*Dekatherm = 10 therms or 1,000,000 British thermal units (MMBtu)

NATURAL GAS



A number of market dynamics could influence future natural gas prices:

- North American economic growth
- Regulatory costs that add to the cost of accessing, producing or transporting natural gas
- Advances in exploration and production tools and technologies

Production

In 2016, Idaho completed its first full year of natural gas production for commercial use. Alta Mesa Holdings LP is currently the only natural gas producer in Idaho.

Alta Mesa operations overview:

- 17 wells located in the Payette, Idaho basin.
- 8 wells are producing natural gas, condensate, oil, and other liquids.
  The Company's processing facility is located at Willow Creek near Payette.
  End Uses:
- Oil and condensate are collected at the Willow Creek facility and transported by truck to the Ontario Oregon railyard and shipped to Salt Lake City and other destinations for processing.
- Intermountain Gas Company is connected to one of Alta Mesa's wells and purchases natural gas to serve the Payette Idaho area.
- Williams Northwest Pipeline Company is connected to Alta Mesa and purchases natural gas for its interstate pipeline business.

Summary

Idaho residential, commercial and industrial users of natural gas continue to benefit from low natural gas prices and plentiful supply. Advancements in exploration, extraction, and production techniques continue to transform the industry.

NATURAL GAS

NOTABLE LEGISLATIVE DEVELOPMENTS

Law establishes Oil and Gas Conservation Commission

In the 2017 Legislative session, Idaho lawmakers unanimously passed House Bill 301 to regulate the exploration, drilling and production of oil and gas resources on private, state and federal land throughout the state.

The law called for the creation of the Idaho Oil and Gas Conservation Commission consisting of three technical experts, the state Department of Lands director and a county commissioner from a county in which oil and gas production is underway.

The law clarifies definitions and reporting requirements for the production and sale of oil and gas in Idaho, while providing protection for landowners, penalties for noncompliance and public access to information related to the production of oil and gas. The information is hosted on a new website, https://ogcc.idaho.gov.

Law establishes requirements for oil and gas producers

Senate Bill 1098 requires oil and gas producers to file monthly statements with the Idaho Tax Commission documenting the name, description and location of every well or oil and gas field that contains wells. The law, which took effect July 1, authorizes the state Tax Commission to conduct audits of oil and gas producers every three years.

The intent of the new law was to clarify the reporting requirements of oil and gas producers.

NATURAL GAS CASES

Tentative settlement reached in Avista rate case

In June, Avista asked for approval of a two-year plan calling for rate increases in 2018 and 2019. The company said the request was driven by the need to replace or upgrade its aging infrastructure.

A tentative settlement agreement was reached in late September. If approved by the Commission, the settlement would lead to an average rate increase for natural gas service of 1.9 percent in 2018 and 1.8 percent in 2019.

The company's original proposal called for increases of 5.7 percent in 2018 and 3.3 percent in 2019. The proposed settlement also calls for an increase of 75 cents to the basic charge, raising it to $6 per month.

Among the planned capital investments necessitating the need to increase revenue are an ongoing project to replace portions of a natural gas distribution line, upgrades to the company's transmission and distribution system and technological improvements.

The proposed settlement calls for reductions or delays in a number of projects included in the company's original proposal, including a delay in a new meter data management system that decreases the revenue requirement by $415,000, and $300,000 in reductions tied to miscellaneous expenses.

The proposed settlement agreement was reached between several parties to the case after a settlement conference in late September. Those parties include Clearwater Paper, Idaho Forest Group and the Community Action Partnership Association of Idaho. Sierra Club and the Idaho Conservation League opposed the settlement agreement.

For natural gas service, the settlement terms are designed to increase annual billed revenue by $1.2 million in 2018 and $1.1 million in 2019. The original proposal would have increased annual billed revenue by $3.5 million in 2018 and $2.1 million in 2019.

The revenue increases are based on a 9.5-percent return on equity, down from a 9.9-percent return on equity in Avista's original proposal.

It the settlement is approved, a residential natural gas customer using an average of 63 therms per month would see an increase of $1.13 per month, for a monthly bill of $53.74. In 2019, that customer would see an increase of $1.09 per month for a monthly bill of $54.83.

Commission accepts Avista long-range planning document

In February, the Commission accepted Avista's Natural Gas Integrated Resource Plan (IRP). The utility is required to file an updated IRP with state regulators every two years. The plan outlines the ways in which Avista expects to meet the demand for natural gas among its customers.

The IRP anticipated annual growth of about one-half percent over the next decade, with about a 0.8 percent increase in peak-day use. The IRP said the utility was well-positioned to meet the increased de-

NATURAL GAS CASES

mand through a diversified portfolio of natural gas supply resources, including storage, firm capacity rights on six pipelines and contracts to purchase natural gas from several supply basins.

Among the projects highlighted in the plan were an $8 million Coeur d'Alene High Pressure Reinforcement project to address low-pressure conditions in the Hayden Lake system that generally occur when demand is high during winter conditions, the Schweitzer Mountain Road High Pressure Reinforcement ($1.5 million) and 2019 gate station improvements at Athol, Bonners Ferry and Genesee.

Commission approves Intermountain Gas efficiency program

The Idaho Public Utilities Commission in September approved an Intermountain Gas proposal to create and fund a new efficiency program for residential customers.

Intermountain's Demand Side Management (DSM) Program is funded through an efficiency rider or surcharge of 0.367 cents per therm – that is 22 cents per month for the average customer using 61 therms per month.

Intermountain's DSM program is expected to cost $770,000 in its first year, with $600,000 earmarked for rebates to customers who enact efficiency measures on new or existing homes.

In order for the program to be funded by the efficiency rider, the Commission requires that a utility demonstrate that costs related to the programs over the previous 12 months were prudently incurred.

If the costs are found to be unreasonable, or to exceed the benefit to customers, they are borne by shareholders rather than customers.

Several tests are used to determine prudency, or whether the benefits outweigh the costs.

In a successful DSM program, all customers benefit because the change in energy use helps the utility avoid or defer building costly new generation resources or avoid the need to procure additional resources at an additional cost.

Commission approves decrease to surcharge

In September, the Commission approved an Intermountain Gas proposal to decrease a recovery mechanism known as the annual Purchased Gas Cost Adjustment (PGA).

The change lowered the monthly bill for the average residential customer by $3.32. Commercial customers saw an average decrease of $16.42 per month, while two customer classes – large volume and transportation – saw a slight rate increase.

The PGA is adjusted each fall with Commission approval, to reflect changes in expenses related to the natural gas purchased from suppliers as well as changes in transportation, storage and other variable costs.

In addition to changing the PGA to reflect the cost of providing natural gas to Intermountain's customers, the company requested Commission approval to recover $699,114 in expenses incurred for audit-

NATURAL GAS CASES

ing and consultation from third parties during its recently resolved general rate case.

The Commission approved the recovery via the PGA of $378,614 over five years, or $75,723 per year. It did not disallow the recovery of the balance of the expenses but said the prudency of the remaining $319,963 had not been determined.

Those expenses will be considered during the company's next general rate case.

WATER

Regulated water companies

Company	Customers	Nearest city/town
CDS Stoneridge Utilities, LLC	358	Blanchard
Diamond Bar Estates Water Company	46	Rathdrum
Eagle Water Company, Inc.	3,546	Eagle
Falls Water Company, Inc.	4,500	Ammon
Grouse Point Water	24	Kuna
Happy Valley Water System	27	Athol
Island Park Water Company	362	Island Park
Kootenai Heights Water System, Inc.	11	Kootenai
Mayfield Springs Water Company	76	Kuna
Morning View Water Company, Inc.	108	Rigby
Picabo Livestock Company	28	Picabo
Ponderosa Terrace Estates Water System, Inc.	22	Sandpoint
Resort Water Company	422	Sandpoint
Rickel Water Company	38	Coeur D'Alene
Rocky Mountain Utility Company, Inc.	101	Rigby
Schweitzer Basin Water LLC	439	Sandpoint
Spirit Lake East Water Company	301	Coeur D'Alene
Suez Water Idaho Inc.	88,400	Boise
Sunbeam Water Company	22	American Falls
Teton Water and Sewer Company, LLC	285	Driggs
Troy Hoffman Water Corporation	147	Coeur D'Alene

WATER CASES

Grouse Point Water receives approval to raise rates and charges

In September, the Commission approved increases to rates and charges for customers of Grouse Point Water Company near Kuna.

The changes included an increase to the monthly customer charge, from $22 to $86, and to charges based on the amount of water used.

The changes took effect Oct. 15 and call for usage charges based on an inclining block rate structure that assesses a higher rate when usage exceeds certain amounts.

Grouse Point customers who use up to 8,000 gallons in a month are now charged $2.50 per 1,000 gallons used. The rate increases to $3.75 per 1,000 gallons for monthly usage between 8,001 and 20,000 gallons. It climbs to $5 per 1,000 gallons for monthly usage exceeding 20,000 gallons.

Under the previous rate structure, customers paid 50 cents per 1,000 gallons used when monthly consumption exceeded 8,000 gallons. There were no usage charges for customers who consume less than 8,000 gallons per month.

Grouse Point Water provides service to 24 customers.

In requesting Commission approval to raise rates, the company said revenue had fallen short of operational expenses every year since 2003, when its previous rates were set. Without a rate increase, the company said, it would be unable to continue operations.

Grouse Point had proposed raising the monthly customer charge to $113.86 and implementing consumptive charges with two tiers separated at 8,000 gallons - $1.83 per 1,000 gallons for those who use less than 8,000 gallons in a month, and $5 per 1,000 gallons for usage in excess of 8,000 gallons.

In its proposal, the company said revenue between 2012 and 2015 covered approximately 40 percent of its expenses for basic operations and maintenance, creating a deficit in excess of $10,000. In addition, the company contended its rates did not reflect $127,441 in capital improvements made in 2009 and 2013. Those improvements included installation of a new well, two pumps and associated equipment needed to comply with federal drinking water standards involving uranium that were established in 2004.

Commission approves Falls Water request to build new well

In September, the Commission approved a request from Falls Water Company to construct a new well in order to resolve problems with water pressure in its service territory.

The project is estimated to cost $647,215 and calls for construction of a well, well house, pumping equipment and controls.

The decision does not immediately impact rates; however, the Commission's order allows project expenses to be considered in Falls Water's next rate case. Company estimates indicate the project could lead to a rate increase of between 3.4- and 4.4 percent, but all expenses related to the project will be reviewed for accuracy and reasonableness before they are included in future rates.

WATER CASES

Falls Water serves approximately 4,700 customers in Bonneville County, east of Idaho Falls.

Officials with the Idaho Department of Environmental Quality notified the company in July 2016 that it had failed to comply with water pressure requirements of the Idaho Rules for Public Drinking Water Systems.

DEQ officials suggested that corrective action could include water-use restrictions or an increase in system capacity through additional sources, storage or pumping.

When the potential solutions were deemed inadequate or cost prohibitive, Falls Water sought to add capacity through the construction of a new well.

The Commission found that the company's proposal "appears to be the most cost-effective means of providing adequate service to its customers."

Morning View Water receives approval to raise rates and charges

In late 2016, the Commission approved a rate increase for customers of Morning View Water Company in Rigby.

The change raised the monthly minimum charge from $32.62 to $50 for quarter-acre lots, and introduced volumetric charges based on the amount of water used each month.

These consumption-based charges are now split into two tiers. For a customer with a quarter-acre lot, the first tier is 15 cents per 1,000 gallons used per month, up to 10,000 gallons. Usage beyond that amount is assessed at 48 cents per 1,000 gallons used per month.

The changes were expected to increase the company's annual revenue by $93,727, or nearly $8,000 less than the revenue generated under Morning View's proposal, which did not call for volumetric charges.

In its application to the Commission, the company said its first rate increase since 2007 was needed in order to meet expenses related to the installation of a third well, along with upgrades to two existing wells.

Morning View provides water service to approximately 100 customers in and around Rigby in eastern Idaho.

The Commission received a number of comments from customers opposed to the company's request.

TELECOMMUNICATIONS

Regulated telecommunications companies

Albion Telephone Corp.	Albion
Cambridge Telephone Co.	Cambridge
CenturyLink*	Boise
CenturyTel of Idaho, Inc.*	Salt Lake City, UT
CenturyTel of the Gem State*	Salt Lake City, UT
Citizens Telecommunications Company of Idaho*	Beaverton, OR
Columbine, dba Silver Star Communications	Freedom, WY
Frontier Communications Northwest, Inc.*	Beaverton, OR
Direct Communications Rockland, Inc.	Rockland
Inland Telephone Co.	Roslyn, WA
Fremont Telecom, Inc.	Missoula, MT
Midvale Telephone Company	Midvale
Oregon-Idaho Utilities, Inc.	Nampa
Pine Telephone System, Inc.	Halfway, OR
Potlach Telephone Company	Kendrick
Rural Telephone Company	Glenns Ferry

* These companies are no longer rate regulated; however, they are still regulated for customer service.

TELECOMMUNICATION CASES

ITSAP surcharge suspended for 2017 budget year

In May, the Commission suspended a surcharge assessed on all telephone lines. The surcharge had been 1 cents per month per line, with the revenue earmarked for the Idaho Telecommunications Service Assistance Program, which provides qualified low-income landline and cell phone users with a discount of $2.50 per month.

While the number of telephone lines supporting the fund decreased in 2016, the number of recipients of the subsidy declined more sharply. That prompted the Commission to suspend the charge for the 2017 budget year.

The surcharge has declined significantly in the last two decades, from 13 cents per month in 1998, to 7 cents in 2013, and 3 cents in 2014.

In addition to ITSAP, a federal program, Lifeline, provides $9.25 per month to help qualifying low-income citizens access phone and broadband service.

A number of factors played into the Commission's decision to suspend the surcharge, including:

- The number of ITSAP recipients dropped 42 percent from 2015 to 2016, and more than 85 percent since 2011 (from 25,310 to 3,880).
- The number of "land lines" declined 17 percent, to an average of 363,888 per month, from 2015 to 2016, and the number of wireless lines dropped 2 percent, to 1,384,720.
- The gross surcharge revenue for 2016 was reported at $235,421, of which 18 percent was assessed on wireline services and 82 percent was assessed on wireless services.
- Administrative costs for the program reported by eligible telecommunications carriers decreased from $33,089 in 2015 to $23,235 in 2016.
- The ITSAP fund cash balance at the end of 2016 was $1,354,852.

Surcharge on land lines increases, Universal Service Fund scrutinized

Faced with declining revenue as Idahoans increasingly abandon land line phone service, in August 2017 the Commission raised a monthly surcharge on land lines and questioned the sustainability of the Idaho Universal Service Fund (IUSF).

The fund was established in 1988 to ensure all Idahoans have access to local telephone service at reasonable rates.

This is accomplished by taking revenue collected from a surcharge on land-line users and long-distance call minutes, and distributing it to telecommunications carriers that meet eligibility requirements.

Over the last several years, however, revenue has been insufficient to cover distributions. In the most

TELECOMMUNICATION CASES

recent fiscal year, the fund collected nearly a half-million dollars less than it distributed. The trend prompted the Commission to raise the monthly surcharge on each residential line to 25 cents, up from 12 cents, and to 44 cents for each business line, up from 20 cents.

The change took effect Sept. 1, 2017.

The cost for each minute of a long-distance call also increased, from ½ cent per minute to 0.9 cents per minute.

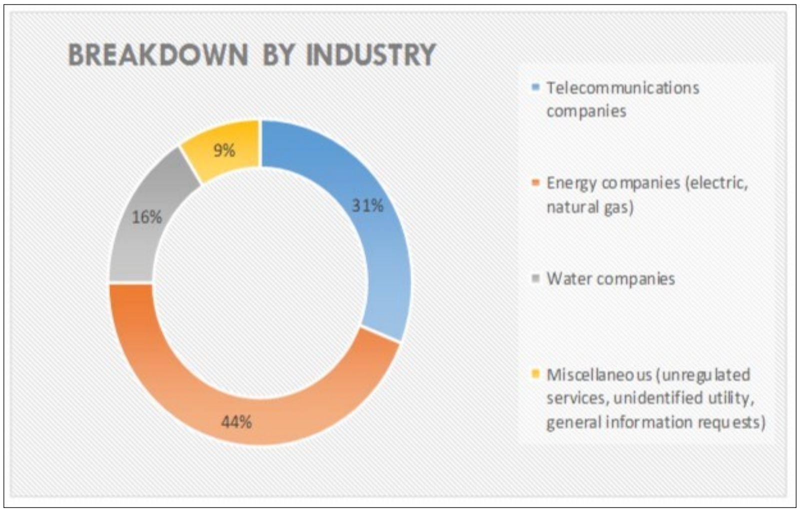
The changes are expected to allow the fund to meet its obligations for the 2018 fiscal year, but the Commission expressed concern that raising the surcharge will cause more Idahoans to abandon their land lines, exacerbating the trend and eventually making the fund unsustainable.

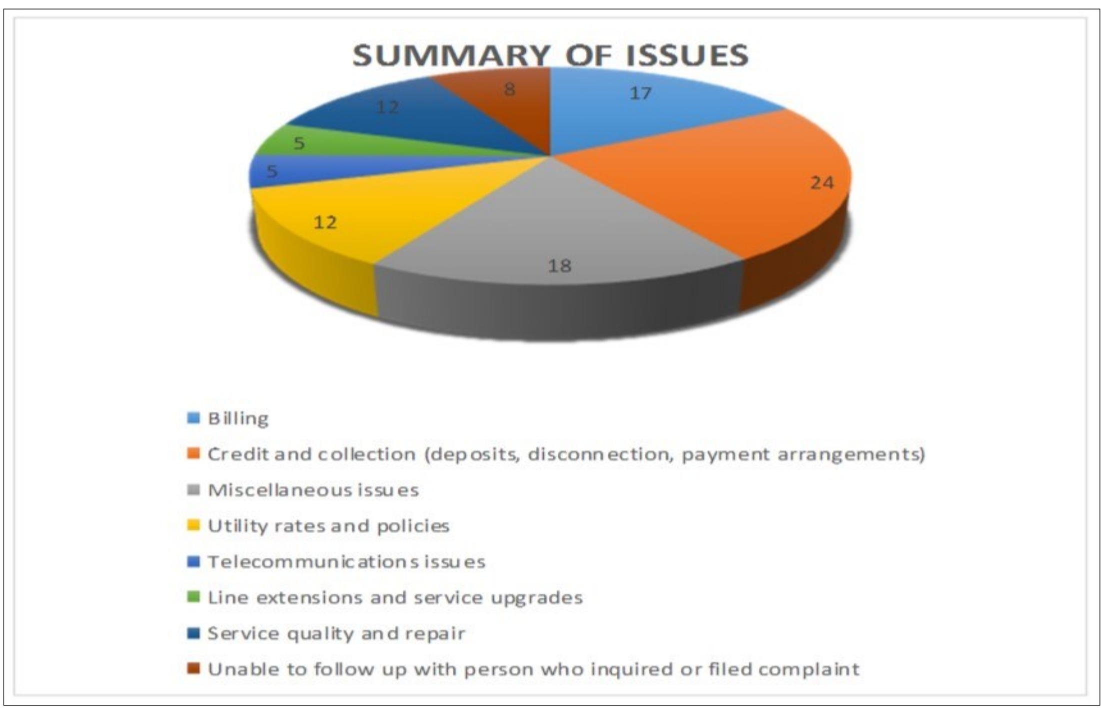
To address this, the Commission opened a generic docket to facilitate communication with the general public, telephone company representatives and other stakeholders, with a goal of developing a sustainable approach for the fund in a declining industry where land lines are being replaced with new technology such as cell phones and Voice over Internet Protocol.

CONSUMER ASSISTANCE

Commission issues annual consumer assistance report

The Consumer Assistance staff responded to 1,424 complaints and inquiries in calendar year 2017*, 91 percent of which were from residential customers. The first chart below illustrates the complaints and inquiries by industry, while the second chart summarizes the types of issues reported to the IPUC.





While the Consumer Assistance Staff is able to respond to most inquiries without extensive research, about 75 percent of complaints required investigation by the staff. About 44 percent of investigations resulted in reversal or modification of the utility's original action. Payment terms were negotiated in 20 percent of the investigations.

*As of Nov. 15, 2017

REGULATING IDAHO'S RAILROADS

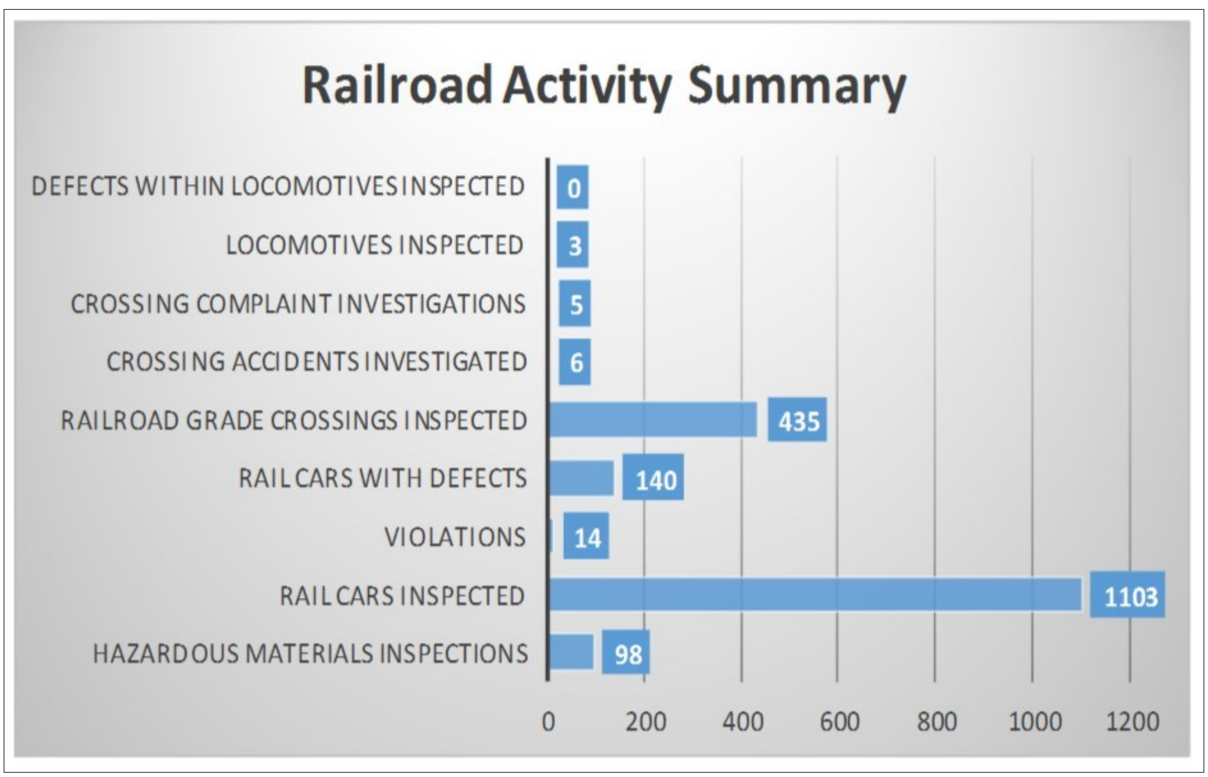
More than 900 miles of railroad track in Idaho have been abandoned since 1976. Federal law governs rail line abandonments. The federal Surface Transportation Board (formerly the Interstate Commerce Commission) decides the final outcome of abandonment applications. Under Idaho law, however, after a railroad files its federal notice of intent to abandon, the IPUC must determine whether the proposed abandonment would adversely affect the public interest. The commission then reports its findings to the STB.

In reaching a conclusion, the commission considers whether abandonment would adversely affect the service area, impair market access or access of Idaho communities to vital goods and services, and whether the line has a potential for profitability.

The Idaho Public Utilities Commission also conducts inspections of Idaho's railroads to determine compliance with state and federal laws, rules and regulations concerning the transportation of hazardous materials, locomotive cab safety and sanitation rules, and railroad/highway grade crossings.

Hazardous material inspections are conducted in rail yards. In 1994, Idaho was invited to participate in the Federal Railroad Administration's State Participation Program. IPUC has a State Program Manager and one FRA certified hazardous material inspector.

The IPUC inspects railroad-highway grade crossings where incidents occur, investigates citizen complaints of unsafe or rough crossings and conducts railroad-crossing surveys.



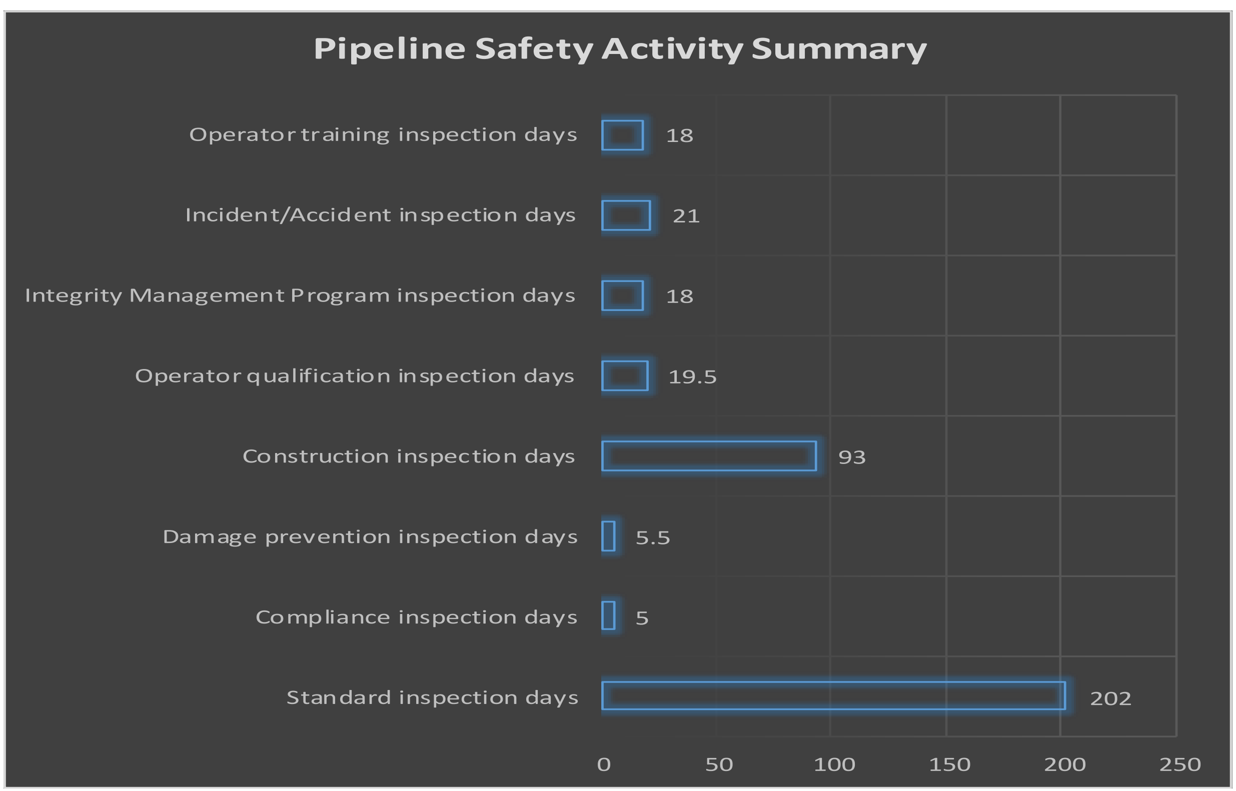
REGULATING IDAHO'S PIPELINES

Idaho Code 61-515 empowers the Idaho Public Utilities Commission to require every utility to "maintain and operate its line, plant, system, equipment, apparatus, and premises in such a manner that promote and safeguard the health and safety of its employees, customers and the public."

Pursuant to 49 U.S.C Section 60105, Chapter 601, the Idaho Public Utilities Commission is a certified partner with the U.S. Department of Transportation Pipeline Hazardous Material Safety Administration. The federal/state partnership provides the statutory basis for the pipeline safety program and establishes a framework for promoting pipeline safety through federal delegation to the states for all or part of the responsibility for intrastate natural gas pipeline facilities under annual certification.

Under the certification, Idaho assumes inspection and enforcement responsibility with respect to more than 8,300 miles of intrastate natural gas pipelines over which it has jurisdiction under state law. With the certification, Idaho may adopt additional or more stringent standards for intrastate pipeline facilities provided the standards are compatible with federal regulations.

The Idaho Public Utilities Commission has a state program manager and three trained and certified pipeline safety inspectors who conduct records audits and field installed equipment inspections on all intrastate natural gas pipeline operators under its jurisdiction.



This report satisfies Idaho Code 61-214; this is a "full and complete account" of the most significant cases to come before the commission during the 2017 calendar year. (The financial report and natural gas report cover Fiscal Year July 1, 2016 through June 30, 2017.)

Interested parties may review the Commission's agendas, notices, case information and decisions by visiting the IPUC's Web site at: www.puc.idaho.gov. Commission records are also available for public inspection at the Commission's Boise office, 472 W. Washington St., Monday through Friday, 8 a.m. to 5 p.m.

The Idaho Public Utilities Commission, as outlined in its Strategic Plan, serves the citizens and utilities of Idaho by determining fair, just and reasonable rates for utility commodities and services that are to be delivered safely, reliably and efficiently. During the period covered by this report, the Commission also had responsibility for ensuring all rail services operating within Idaho do so in a safe and efficient manner. The Commission also has a pipeline safety section that oversees the safe operation of the intrastate natural gas pipelines and facilities in Idaho.

Costs associated with this publication are available from the Idaho Public Utilities Commission in accordance with Section 60-202, Idaho Code, PUC 12-20-2017.

Questions?

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