ELECTRIC

Avista Utilities

<u>2018 Average Number of Customers/Avg. Revenue/kwh*</u>

340,310 Residential Customers/$0.10180

42,618 Commercial Customers/$0.09990

1,318 Industrial Customers/$0.06209

Idaho Power Company

<u>2018 Average Number of Customers/Avg. Revenue/kwh*</u>

418,906 Residential Customers/$0.1030

80,261 Commercial Customers/$0.0767

113 Industrial Customers/$0.0567

Rocky Mountain Power

<u>2018 Average Number of Customers/Avg. Revenue/kwh*</u>

PacifiCorp/Rocky Mountain Power

60,959 Residential Customers/$0.1112

8,425 Commercial Customers/$0.0895

5,544 Industrial Customers/$0.0733

*The information above shows each regulated electric utility's average number of customers per customer class and the average revenue per kilowatt-hour (kWh) for 2018.

Avista

Regulators deny Avista-Hydro One deal

The Idaho Public Utilities Commission denied the proposed merger of Avista Utilities and Hydro One.

In its order, the Commission said the transaction is prohibited by Idaho Code § 61-327, which limits the ability of an electric utility to sell assets in certain situations.

Although Hydro One is an investor-owned utility, the Province of Ontario is its largest shareholder with 47 percent of outstanding shares. The Province also maintains unique governance agreements with Hydro One, granting it significant control and influence over the utility.

That lack of independence "dictates our decision to reject the proposed merger," the Commission said in its order.

"Hydro One is not purely a private, publicly traded corporation," the Commission said. "Rather, the management of Hydro One is subject to the Province's political pressure, legislative power, and special governance agreements."

The companies filed their joint application for Commission approval in September 2017.

The proposal called for Avista to become a wholly owned subsidiary of Hydro One, the largest electric transmission and distribution utility in Ontario. Avista would have continued to operate out of its headquarters in Spokane under the same name, with existing staffing levels and management team.

In April, all parties to the case at the time entered into a proposed settlement agreement that contained provisions intended to protect Avista and its customers from financial risk associated with the transaction.

Among 73 commitments outlined in the proposed settlement were nearly $16 million in rate credits for Idaho customers over five years and more than $5 million to fund energy efficiency, weatherization, conservation and low-income assistance programs over a 10-year period.

More than 600 public comments were submitted in the case, nearly all in opposition to the proposed merger, and testimony was accepted at three public hearings held in Avista's service territory in mid June.

A technical hearing set for late June was postponed until November after Hydro One's chief executive officer retired and its entire board of directors resigned under political pressure from the premier of the Province of Ontario shortly after the premier took office in June.

In mid-November, an amended settlement proposal was submitted to the Commission.

It contained 79 commitments intended to "address the impact of the management changes and the potential for Provincial involvement in the affairs" of Hydro One and Avista.

In its order, the Commission commended both the extensive public participation and the significant efforts made by the parties to the case to reach a settlement intended to protect Avista's property and customers.

Despite those efforts, the Commission emphasized that its decision is guided and constrained by Idaho Public Utilities Law.

"The prohibitions of Idaho Code § 61-327 cannot be nullified with generous settlement terms and robust ring-fencing provisions," the Commission said.

Idaho Code § 61-327 prohibits the transfer of assets from a regulated electric utility to an entity that is "owned or controlled, directly or indirectly, by … any other state."

Idaho Code § 61-327 more specifically bars the transfer if the entity is "acting in concert or arrangement" with "any other state."

Although the applicants argued that "any other state" should be interpreted narrowly, to include only other states within the United States, the Commission disagreed.

"The Applicants' narrow concept of state would yield the absurd result of prohibiting purchases by entities owned by other states of the United States, while allowing such transactions if the entity is owned by a foreign country," the Commission said.

Hydro One was a Crown Corporation owned entirely by the Province of Ontario until 2015, when it was partially privatized. Today, the Province is not only Hydro One's largest shareholder but it also maintains a unique governance agreement with the company that prohibits any other shareholder from owning more than 10 percent of Hydro One's common shares, in addition to a 2018 letter agreement that spells out how Hydro One will be governed and the Province's role in its governance.

While the applicants assert that these agreements are intended to protect Hydro One's independence from the Province, the Commission said the resignations of the utility's CEO and board in June indicate otherwise.

"It is abundantly clear that the Province does not have to own 51 percent of Hydro One in order to effectively control the company," the Commission said. "Based on the recent events surrounding the Province's intrusions into Hydro one corporate affairs, any other conclusion would be unreasonable and ignorant in light of the uncontested facts and evidence. Consequently, we find that Hydro One has acted in concert with the Province of Ontario, formally and informally, directly and indirectly."

The Idaho Commission was one of five state regulatory entities required to approve the merger. The Washington Utilities and Transportation Commission denied the proposal in early December.

Had the merger been approved, Avista would have gone from being one of the smallest regulated electric utilities in North America to being a part of one of the largest, with more than $25.4 billion in assets.

Avista provides electric service to approximately 378,000 customers (130,000 in Idaho) and natural gas service to about 342,000 customers (approximately 82,000 in Idaho). Hydro One has approximately 1.3 million customers.

Avista customers to see slight increase in annual rate calculation

Avista customers will pay slightly more for electricity this fall after state regulators approved several rate adjustments.

Combined, the changes approved by the Idaho Public Utilities Commission will result in a 3.1 percent increase to residential rates on October 1.

Residential electric customers in Idaho using an average of 898 kilowatt hours (kWh) per month would see their monthly bills increase from $82.57 to $85.12, an increase of $2.55 per month.

Two of the changes are to annual rate adjustment mechanisms: the Fixed Cost Adjustment is set to increase by 1.7 percent, while the Power Cost Adjustment will increase by 2.91 percent.

The third adjustment results from Bonneville Power Administration’s (BPA) Residential Exchange Program (REP). Customers will receive a credit on their power bill of 1.6 percent.

Each year the Commission reviews these annual rate calculations to determine whether customer rates should increase or decrease.

Here is a closer look at each of these changes:

Commission accepts Avista’s long-range plan for natural gas operations

State regulators have accepted Avista Utilities’ 2018 natural gas Integrated Resource Plan, a 185-page document that outlines the company’s plans for meeting customer demand over the next 20 years.

Avista is required to file a natural gas Integrated Resource Plan (IRP) with the Idaho Public Utilities Commission every other year.

The IRP is intended to demonstrate the utility’s plan to provide safe, reliable and economic natural gas service to its customers in the most cost-effective manner in a number of scenarios, covering various weather and market conditions.

Commission acceptance does not signal approval or endorsement of “any particular element of the plan, nor an approval of any resource acquisition or proposed action included in the IRP.” Instead, Commission acceptance serves as acknowledgement that the company has met its requirement to file the plan.

Avista’s 2018 IRP notes that while there has been an increase in the supply of natural gas in the US, and subsequent low costs have led to increasing interest in natural gas, the utility does not anticipate growth in demand among its traditional residential and commercial customers throughout the planning period. Lower prices could lead to increased demand for natural gas among Large Industrial customers, however.

The IRP anticipates that the total number of customers will grow from 348,000 today (approximately 83,000 customers are in northern Idaho) to 412,000 in 2037, at an average annual pace of 1.3 percent, with the average daily demand increasing at a rate of 0.02 percent each year.

Avista plans to rely on a diversified portfolio of supply resources, including storage, firm capacity rights on six pipelines and contracts for the purchase of natural gas from multiple supply basins to meet that demand.

Analysis conducted for the IRP found no resource deficiencies through the 20-year planning period in all conditions except the High Growth and Low Price scenario. Under the Expected Case scenario, existing resources were found to be sufficient to meet demand through 2037.

The IRP also cites that the potential for efficiency and conservation, or Demand Side Management (DSM), to offset expected load growth.

That differs from the company's 2016 IRP, which found that low natural gas prices rendered DSM programs cost-ineffective.

The public played a role in the development of the IRP, including four meetings of the utility's Technical Advisory Committee (TAC), which consists of customers, representatives from peer utilities, Commission staff and others.

In its order, the Commission commended the company's ongoing efforts to keep customers informed, through the TAC and other avenues.

"We encourage the company to continue in its efforts to engage affected and interested persons," the Commission said.

Commission to hold public hearing on Avista rate case

Parties to an Avista rate case have proposed a settlement that reduces the utility's annual electric base revenues in Idaho. If approved by the Idaho Public Utilities Commission, the settlement would decrease annual base electric revenues by $7.18 million, or 2.84 percent, effective Dec. 1, 2019.

Avista's original proposal called for an increase in electric base revenues of $5.3 million, or 2.1 percent.

The Commission held a public workshop and public hearing for Idaho customers of Avista at 6 p.m. (PST) on November 7, 2019, in Coeur D'Alene, Idaho.

A technical hearing held on November 22, 2019, in the Commission's hearing room. Technical hearings allow intervening parties to present testimony and evidence.

A public telephonic hearing was held on November 22, 2019, which allowed Avista's Idaho customers an additional opportunity to provide testimony that will be made part of the formal case record.

The Spokane-based company said the primary driver for its original request is an increase in net plant investment (including return on investment, depreciation and taxes, and offset by the tax benefit of interest) from that currently authorized. In addition, net power supply expense is reduced from the currently authorized level, offsetting the Company's overall increase as originally requested.

Idaho state law requires that regulated utilities be allowed to recover their prudently incurred expenses and earn a reasonable rate of return, which is established by the Commission. The burden of proof is on the utility to demonstrate that additional capital investment was necessary to serve customers and, if so, that the expenses were prudently incurred.

The proposed settlement calls for several reductions to the company's original proposal. For Avista's electric operations, those changes include a $2.2 million decrease to the Company's proposed 2019 revenue requirement tied to a reduction in return on common equity, a reduction of nearly $744,000 through the elimination of officer incentive pay and salary increases and a reduction in non-officer incentives and salary increases, and a reduction of approximately $6.4 million due to reduced power supply costs.

The proposed settlement agreement was reached between the parties to the case after a settlement conference in late September. Those parties include the Commission Staff, Clearwater Paper Corporation, Idaho Conservation League, Inc., Idaho Forest Group, LLC, the Community Action Partnership Association of Idaho, Inc. and Walmart, Inc.

If approved by the Commission, the proposed settlement would decrease Avista's annual base electric revenues by $7.18 million, beginning on December 1, 2019. The revenue decreases are based on a 9.5-percent return on equity, down from a 9.9-percent return on equity in Avista's original proposal.

For a residential electric customer using an average of 900 kilowatt-hours per month, the proposed settlement would lead to a decrease of $0.86, or 1.0 percent decrease per month for a revised monthly bill of $84.45.

Idaho Power

Idaho Power customers to see slight rate decrease

Idaho Power customers will pay less for electricity this summer after state regulators approved several rate adjustments.

Combined, the changes approved by the Idaho Public Utilities Commission to a 0.65 percent decrease to residential rates on June 1.

That equates to a savings of 59 cents per month for the typical residential customer who uses 950 kilowatt-hours (kWh) per month.

Two of the changes are to annual rate adjustment mechanisms and largely offset each other: The Fixed Cost Adjustment is set to increase by 3.64 percent, while the Power Cost Adjustment will decrease by 3.49 percent.

Another change, a 0.11 percent increase, allows Idaho Power to recover costs associated with the accelerated retirement of the North Valmy coal-fired power plant.

The fourth rate adjustment is a decrease to the Energy Efficiency Rider, from 3.75 percent of base rate revenues to 2.75 percent.

Here is a closer look at each of these changes:

The North Valmy-related surcharge is a 0.11 percent increase for residential customers, or 10 cents more on the monthly bill of the typical residential customer who uses 950 kWh per month.

The increase primarily reflects changes in costs (approximately $1.2 million) associated with the company's exit from operations at the 522-megawatt, two-unit facility that have been incurred since 2016. That is when Idaho Power began tracking the incremental costs and benefits of the plant's early retirement – Unit 1 will close this year, 12 years earlier than originally planned, and Unit 2 will close in 2025, a decade earlier than planned.

The surcharge also includes costs outlined in the North Valmy Project Framework Agreement that Idaho Power reached in early 2019 with the plant's co-owner, NV Energy.

The terms and conditions of the project framework agreement are consistent with those outlined in a Commission-approved 2017 settlement agreement that allowed Idaho Power to recover about $13 million annually until 2028, when Valmy is fully depreciated. That led to a base rate increase of 1.17 percent that took effect in June 2017.

The company contends the early closure of the plant will ultimately provide significant cost savings for its customers - $17.2 million when compared to its prior plans for the facility.

The Fixed Cost Adjustment (FCA) mechanism increased by 3.64 percent for residential customers on June 1.

That equates to an additional $3.49 per month for the typical residential customer who uses 950 kWh per month.

The FCA is an annual rate adjustment tool that separates or decouples energy use from the company's revenue, thereby removing the utility's disincentive to invest in and promote energy efficiency and conservation that can lead to a decline in energy sales.

If fixed costs recovered from customers are less than the fixed costs authorized by the Commission, customers in the Residential and Small General Service classes see a surcharge on their bill. If the company collects more in fixed costs than is authorized, customers in those classes receive a refund.

In 2018, Idaho Power's efficiency programs provided 183,378 megawatt-hours of incremental energy savings – enough to power almost 16,000 homes for a year.

A year ago, the Commission approved an FCA decrease of 3.61 percent.

The Power Cost Adjustment (PCA) mechanism decreased by 3.49 percent for residential customers, effective June 1.

That equates to a monthly savings of $3.35 for the typical residential customer who uses 950 kWh per month.

The PCA is a cost-recovery tool that passes on to customers the benefits and costs of providing energy to Idaho Power's customers.

Like the FCA, it is adjusted each spring to reflect the actual power-supply costs incurred by the company over the previous year.

Those costs can vary significantly from year to year based on hydroelectric generation, market prices for energy, fuel costs, and other factors, and they typically represent one-fourth to one-third of the company's annual costs of providing service.

The PCA has two main components: a forecast and true-up. The forecast projects the company's anticipated power-supply costs, and the true-up balances those forecasted costs with the actual costs incurred by the company over the previous 12 months.

In its application, Idaho Power said last year's power-supply costs were lower than projected, primarily due to water conditions that were better than expected and lower-than-expected natural gas costs. Forecasted power-supply costs for the coming year are also less than they were last year, mainly due to an expected increase in the sale of surplus energy.

A year ago, the Commission approved a PCA decrease of 1.29 percent.

The Energy Efficiency Rider funds the implementation and analysis of the utility's Demand-Side Management (DSM) programs, so-called because they target customer demand for energy rather than the supply.

Lowering the demand helps the company avoid costs associated with building new power plants and purchasing energy on the wholesale market.

As of June 1, this surcharge is assessed at 2.75 percent of the energy charges on a customer's bill, down from 3.75 percent.

That equates to a decrease of 83 cents per month on the bill of the typical residential customer who uses 950 kWh per month.

Idaho Power said the new rate will better align its DSM programs' funding with expenditures reflected in its most recent projections.

The change does not impact the company's DSM programs, which include 16 energy efficiency programs, educational initiatives, and three demand response programs designed to shift customer energy use from periods of peak demand.

Idaho Power, Simplot renew contract for power at Pocatello plant

The Idaho Public Utilities Commission has approved the renewal of an energy sales agreement between Idaho Power and J.R. Simplot Company.

The agreement is for electricity generated at Simplot's fertilizer plant near Pocatello and spans three years.

Simplot's plant contains a cogeneration facility, which produces electricity from the excess heat or steam that is the byproduct of a manufacturing process.

Cogenerators qualify for contracts under the Public Utility Regulatory Policies Act (PURPA), which was enacted in 1978 "to lessen the country's dependence on foreign oil and to encourage the promotion and development of renewable energy technologies as alternatives to fossil fuels."

PURPA requires regulated utilities to buy energy from qualifying facilities at a rate established by state commissions.

That rate is referred to as the avoided cost rate because it is based on the cost the utility avoids by not having to generate the energy itself or purchase from another source.

In Idaho, cogeneration facilities up to 10 average megawatts (aMW) are eligible for contracts at the published avoided cost rate based on the cost of energy at a proxy resource, a combined-cycle combustion turbine. This rate is updated annually to reflect the most recent natural gas forecasts.

The avoided cost rate in this case is adjusted seasonally and for heavy- and light-load hours. It ranges from $36.07 per megawatt-hour (MWh) to $73.92 per MWh.

Simplot's cogenerator is capable of producing up to 15.9 MW, but it is operated so as not to exceed 10 aMW per month under normal conditions. The agreement calls for Idaho Power to accept inadvertent energy that exceeds that amount without reimbursement.

Idaho Power has received the output from the plant since 1991, most recently under an energy sales agreement that ended Feb. 28.

The agreement approved by the Commission includes capacity payments for the entire three-year term since it is the renewal of an agreement receiving capacity payments when it expired.

The agreement was modified slightly from prior contracts for output at the cogeneration facility in that it contains a generation forecasting provision that requires the facility to provide its monthly generation forecast five days ahead of the month estimated rather than a full month ahead. This change represents a compromise among the parties to the case and could provide the utility with more accurate generation forecasting, the Commission said in its order.

"We will continue to evaluate Agreements submitted to us on a case-by-case basis and will evaluate the reasonableness of the provisions in those Agreements in light of the data and information presented to us," the Commission said in its order.

Rocky Mountain Power

Regulators OK Rocky Mountain Power expenses tied to efficiency programs

State regulators have approved Rocky Mountain Power's $8.5 million investment in efficiency programs in 2016 and 2017.

The decision by the Idaho Public Utilities Commission does not impact rates. Instead, it allows the utility to recover the expenses related to its efficiency programs through funds generated by an efficiency rider paid by Rocky Mountain Power customers.

The rider appears on bills as "Customer Efficiency Services" and is set at 2.7 percent of the monthly bill amount.

Costs deemed ineffective are borne by the company's shareholders rather than customers.

Rocky Mountain Power, a division of Pacificorp, provides electric service to approximately 77,000 customers in eastern Idaho.

The utility offers a host of efficiency programs, also referred to as Demand Side Management or DSM since they target the demand for energy rather than the supply.

In addition to reducing power supply expenses for all customers and eliminating or postponing the need to build new generation, DSM programs provide incentives to encourage participating customers to lower their power bills by either using less energy or shifting their usage to off-peak times.

The programs, which include Low Income Weatherization, Home Energy Saver and Non-Residential Energy Efficiency/*watt*smart Business, are subjected to a battery of tests designed to determine whether the savings they realize is greater than their cost. The utility also must demonstrate that the programs benefit all customers, not just those that participate in them.

Rocky Mountain contends its DSM programs saved 15,830 megawatt-hours (MWh) in 2017 and 19,450 MWh in 2016.

Its DSM-related expenses totaled $4,038,931 in 2017, and $4,500,332 in 2016.

Regulators approve decrease to Rocky Mountain Power efficiency surcharge

Rocky Mountain Power customers will see slightly lower bills after state regulators approved a change to the surcharge that funds the utility's efficiency and conservation programs.

The decision by the Idaho Public Utilities Commission lowers the Schedule 191-Customer Efficiency Services Rate Adjustment from 2.7 percent of a customer's total monthly bill to 2.25 percent.

That equates to a decrease of about $5 annually for the average residential customer using 800 kilowatt-hours per month. The change took effect March 1.

Efficiency and conservation programs, also referred to as Demand Side Management or DSM, are designed to encourage customers to use less energy or shift their usage to off-peak times. In addition to helping participants save money by using less energy, DSM programs can help keep rates low for all customers by reducing a utility's power-supply expenses and eliminating or delaying the need to build new generation resources.

Rocky Mountain's DSM programs include Low-Income Weatherization, Home Energy Saver, Home Energy Reports and Non-Residential Energy Efficiency/wattsmart Business.

The utility requested approval to decrease the rider after its DSM-related expenses came in lower than projected in 2016 and 2017.

In its order approving the change, the Commission said it will help align revenues and expenditures, and "represents a reasoned and gradual approach that continues to encourage cost-effective DSM programs while reducing customer bills."

The Commission initially approved recovery of the costs associated with Rocky Mountain's DSM programs through the Schedule 191 rider in 2006. To monitor collections and expenses, the Commission implemented an annual reporting process that includes a review of the programs' cost effectiveness.

Since 2016, when the rider was last adjusted, from 2.1 percent to 2.7 percent, its revenue has exceeded projections while expenses have fallen short of projections. This has led to over-collection of approximately $2.1 million, the company said.

Lowering the collection rate is expected to begin decreasing the over-collected balance and align expenses with revenues over a three-year period.

In its application, Rocky Mountain Power said that, while DSM-related expenses were lower than expected, energy savings associated with the programs exceeded the target established in the company's 2017 Integrated Resource Plan by 5,696 megawatt-hours, about 17 percent, over a two year period.

Rocky Mountain Power provides electric service to approximately 77,600 customers in eastern Idaho.