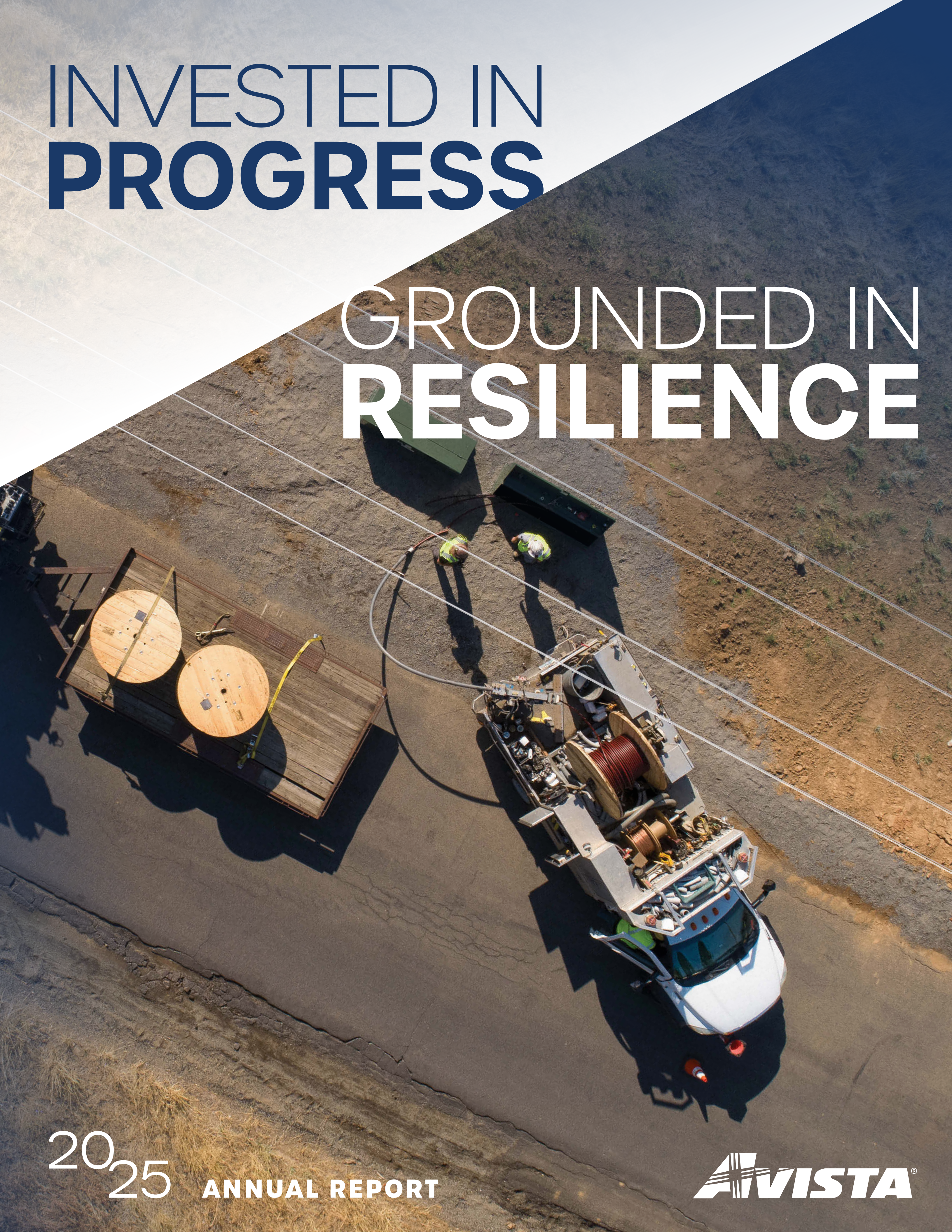
INVESTED IN **PROGRESS**

GROUNDED IN **RESILIENCE**



2025 ANNUAL REPORT

AVISTA®

STRATEGIC UNDERGROUNDING
Moran Prairie, September 2025

INVESTED IN **PROGRESS.** GROUNDED IN **RESILIENCE.**

TO OUR SHAREHOLDERS,

Wow, 2025 was a dynamic first year as CEO, marked by exciting opportunities for growth and investment as well as unprecedented uncertainty and stormy conditions (both figuratively and literally). Yet as we have for 136 years, our teams leaned in, innovated, and delivered for our customers and communities.

Avista remains invested in progress and grounded in resilience, and I want to highlight key achievements through our EPIC strategy.

ENSURE ROBUST ENERGY SUPPLY AND DELIVERY

We continue making smart investments and maintaining support for the important work we do—providing safe, reliable energy. Grants awarded by the Department of Energy for our hydropower resiliency and transmission projects are progressing. We advanced system performance and wildfire grid resiliency by adding cameras, installing weather stations, and expanding covered conductor and underground work. Critical wildfire legislation in Washington and Idaho reflects our leadership in this space.

PARTNER IN THE SHARED CLEAN ENERGY ECONOMY

Avista continues to demonstrate progress on our clean energy goals. We've made selections in our All-Source RFP, and in 2026 will negotiate four potential new energy resources: a 200 MW Montana wind power purchase agreement, a 100 MW battery storage project in eastern Washington, approximately 40 MW of demand response programs, and 14 MW of added capacity from upgrades to existing natural gas turbines in North Idaho. These additions strengthen reliability and support growing customer and clean energy needs.

But our approach to the shared clean energy economy includes projects both large and small. Zooming into the community level, we are partners with several groups advancing a community microgrid project. And, as we work closely with potential large load customers, we are finding opportunities to assess how incremental load can be integrated into our system in a way that supports reliability, affordability, and long-term value.

INSPIRE ENGAGED AND THRIVING EMPLOYEES

Our employees personify "storm strong" in times of adversity. Following record-setting December winds, they worked tirelessly to restore service, demonstrating resilience and commitment. From applying artificial intelligence advancements, drones, and automation to identify efficiencies and enhancements, we are supporting customer resilience, affordability, and sustainability.

COMMIT TO FINANCIAL STRENGTH

Through your support, we invested more than $550M in capital and achieved strong utility results while navigating policy and tariff uncertainty. Our Washington multi-year rate plan and constructive all-party, all-issue settlement outcomes in Oregon and Idaho support long-term financial stability. Our investments and regulatory results set us up well to achieve our long-term EPS growth goal of 4–6% going forward. We will continue to seek fair outcomes in regulatory proceedings and exercise careful management of costs, to deliver the financial returns that our shareholders expect. I am excited and honored to continue serving our customers and communities in 2026 and delivering strong results to you, our investors.

Through these and other accomplishments, we continue to demonstrate that we are **Invested in Progress** and **Grounded in Resilience**. Thank you for the opportunity to serve.

Heather Rosentrater

Heather Rosentrater
President and Chief Executive Officer

PROTECTING OUR COMMUNITIES

We are proactively improving our infrastructure to better protect our communities.

Avista began an exciting new feasibility project in Springdale, WA, focused on wildfire resiliency: the installation and testing of covered conductors.

This technology provides an added layer of defense, especially in regions where dry vegetation and weather conditions elevate fire risk.

Covered conductors are power lines encased in insulating material, which helps prevent sparks and electrical arcs that could ignite wildfires.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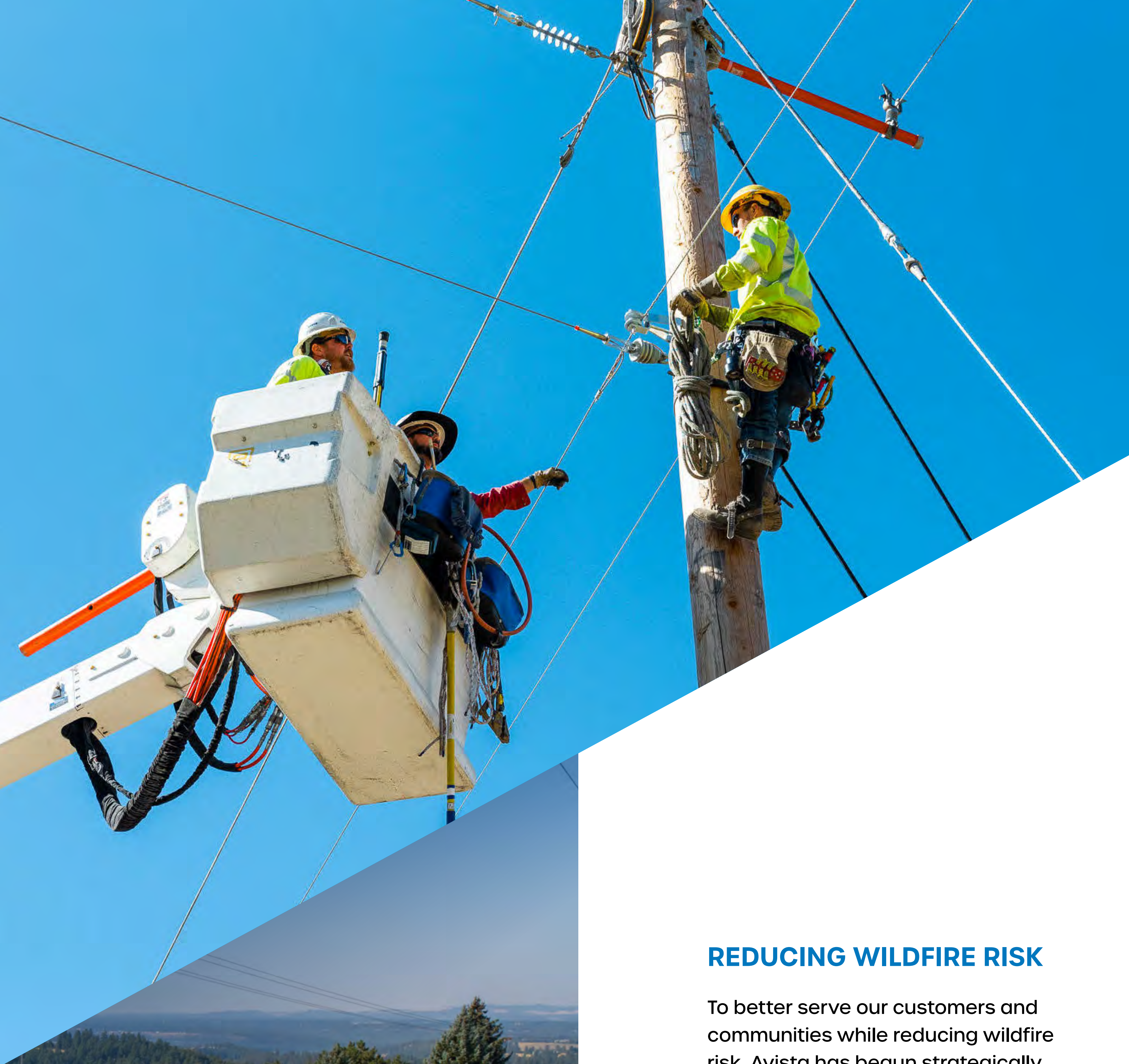
AVISTA
Utilities



REDUCING WILDFIRE RISK

To better serve our customers and communities while reducing wildfire risk, Avista has begun strategically moving sections of overhead power lines underground. We're focusing our efforts in areas that have the highest wildfire ignition risk.

In 2025, Avista completed a strategic undergrounding project along an 11-mile stretch of overhead power lines southeast of the City of Spokane.

FINANCIAL AND OPERATING HIGHLIGHTS

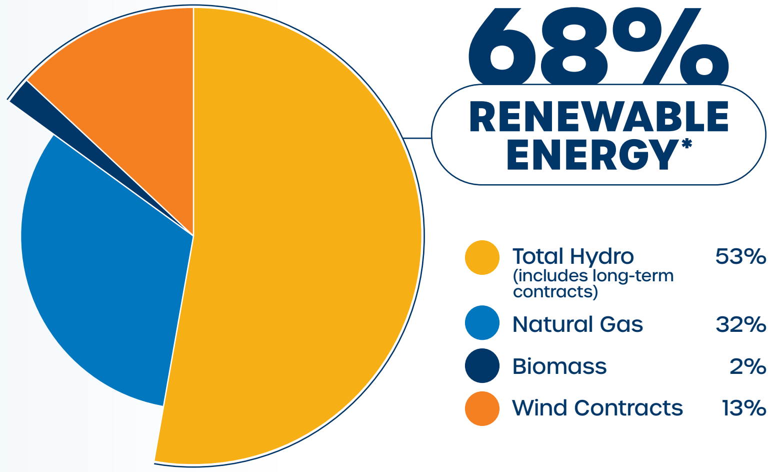
ELECTRICITY GENERATION RESOURCE MIX

As of Jan. 1, 2026 - Excludes AEL&P

Clean Energy Goals

Avista set goals to serve its customers with 100% clean electricity and to be carbon-neutral in its natural gas operations by 2045.

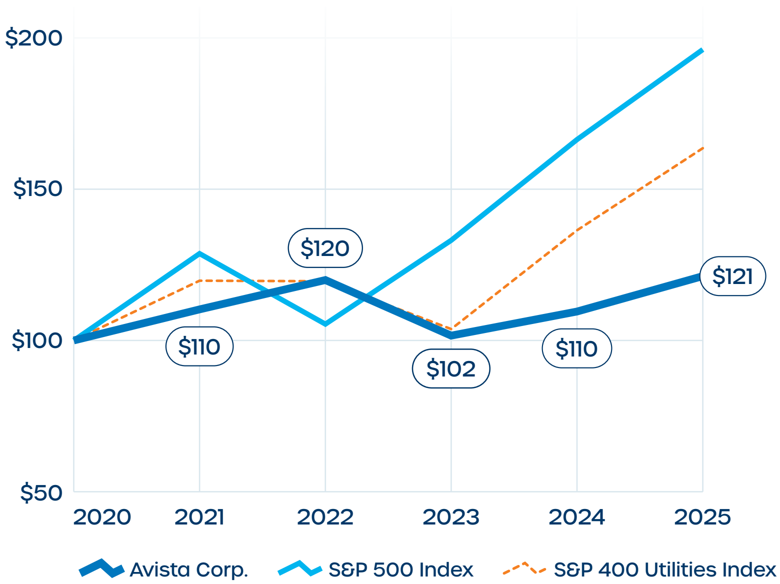
Avista was founded on clean, renewable hydro power in 1889, and the company has a long-standing history of providing clean, reliable and affordable energy to the customers and communities it serves.



*Effective Jan. 1, 2026, Coal is no longer part of the Electricity Generation Resource Mix.

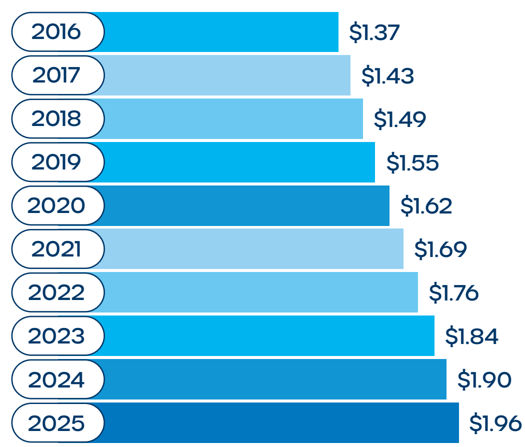
TOTAL SHAREHOLDER RETURN

Assumes $100 was invested in Avista Corp. and each index on Dec. 31, 2020, and that all dividends were reinvested when paid.



COMMON STOCK DIVIDENDS PAID BY AVISTA CORP.

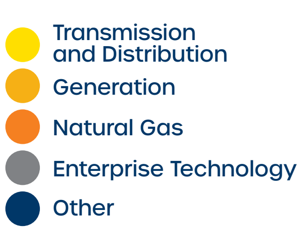
Annualized Dividend (paid in dollars)

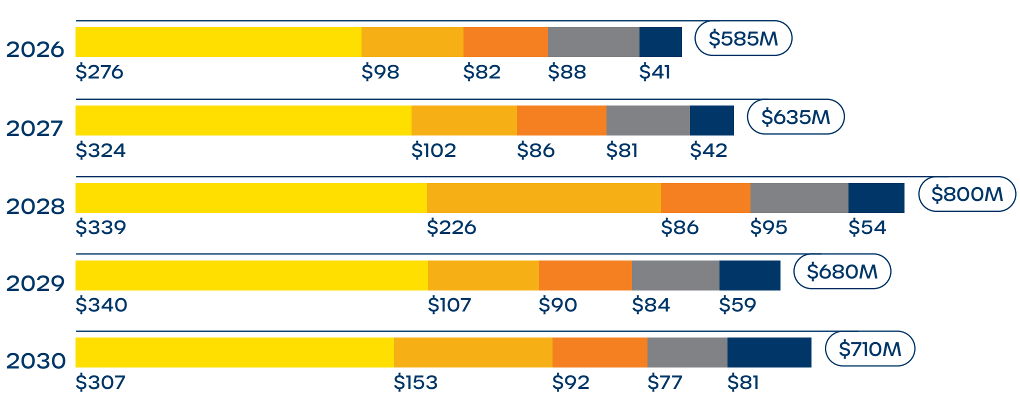


Avista Corp.'s board of directors raised the dividend in each of the last 23 years, reflecting their confidence in the financial strength of the company.

CAPITAL BUDGET

Total capital budget ($ in millions)





(dollars in thousands except statistics and per share amounts or as otherwise indicated)

	2025	2024	2023
FINANCIAL RESULTS			
Operating revenues	$ 1,964	$ 1,938	$ 1,752
Operating expenses	1,610	1,632	1,494
Income from operations	354	306	258
Net income	193	180	171
Total earnings per common share, diluted	2.38	2.29	2.24
Dividends paid per common share	1.96	1.90	1.84
Book value per common share	$ 32.96	$ 32.37	$ 31.83
Average common shares outstanding	80,975	78,725	76,396
Return on average Avista Corp. stockholders' equity	7.3 %	7.1 %	7.1 %
Common stock closing price	$ 38.54	$ 36.63	$ 35.74
OPERATING RESULTS			
Avista Utilities			
Retail electric revenues	$ 1,103	$ 982	$ 887
Retail kWh sales (in millions)	9,257	8,986	8,868
Retail electric customers at year-end	428,608	421,985	416,329
Wholesale electric revenues	$ 187	$ 225	$ 250
Wholesale kWh sales (in millions)	4,457	3,740	3,468
Sales of fuel	$ 20	$ 13	$ (26)
Other electric revenues	34	81	61
Retail natural gas revenues	$ 440	$ 493	$ 507
Wholesale natural gas revenues	52	61	55
Transportation and other natural gas revenues	92	52	9
Total therms delivered (in thousands)	758,285	831,239	817,123
Retail natural gas customers at year-end	386,069	382,920	381,002
Net income	$ 201	$ 179	$ 167
Alaska Electric Light and Power Company			
Revenues	$ 47	$ 50	$ 48
Retail kWh sales (in millions)	402	427	411
Retail electric customers at year-end	17,574	17,785	17,688
Net income	6	8	9
Other			
Revenues	$ 1	$ 1	$ 1
Net loss	(14)	(7)	(5)
FINANCIAL CONDITION			
Total assets	$ 8,359	$ 7,941	$ 7,702
Long-term debt and leases (including current portion)	2,855	2,719	2,640
Long-term debt to affiliated trusts	52	52	52
Total Avista Corp. stockholders' equity	2,709	2,591	2,485

BOARD OF DIRECTORS

Julie A. Bentz, 61
Principal, HOMR LLC
Scio, Oregon
Director since 2021

Donald C. Burke, 65
Langhorne, Pennsylvania
Director since 2011

Kevin B. Jacobsen, 59
Denver, Colorado
Director since 2023

Rebecca A. Klein, 60
Principal, Klein Energy, LLC
Austin, Texas
Director since 2010

Sena M. Kwawu, 57
President, In-Home Services, Cinch Home Services
Kirkland, Washington
Director since 2021

Scott H. Maw, 58
Seattle, Washington
Director since 2016

Scott L. Morris, 68
Chair of the Board, Avista Corp.
Spokane, Washington
Director since 2007

Jeffry L. Philipps, 70
Spokane, Washington
Director since 2019

Heather L. Rosentrater, 48
President & CEO, Avista Corp.
Spokane, Washington
Director since 2025

Heidi B. Stanley, 69
Co-owner & Chair, Empire Bolt & Screw Inc.
Spokane, Washington
Director since 2006

Janet D. Widmann, 59
Operating Partner, Varsity Healthcare Partners
San Francisco, California
Director since 2014

BOARD COMMITTEES

Governance & Corporate Responsibility Committee
Donald C. Burke
Scott H. Maw
Heidi B. Stanley
Janet D. Widmann — Chair

Executive Committee
Donald C. Burke
Scott L. Morris — Chair
Heather L. Rosentrater
Heidi B. Stanley

Audit Committee
Donald C. Burke (Financial Expert) — Chair
Kevin B. Jacobsen
Jeffry L. Philipps
Heidi B. Stanley

Compensation & Organization Committee
Rebecca A. Klein
Scott H. Maw — Chair
Jeffry L. Philipps

Finance Committee
Julie A. Bentz
Sena M. Kwawu — Chair
Scott L. Morris
Janet D. Widmann

Environmental, Technology & Operations Committee
Julie A. Bentz
Kevin B. Jacobsen
Rebecca A. Klein — Chair
Sena M. Kwawu

CORPORATE & BUSINESS UNIT OFFICERS

Heather L. Rosentrater, 48
President & CEO

Kevin J. Christie, 58
Senior Vice President, CFO, Treasurer & Regulatory Affairs Officer

Bryan A. Cox, 56
Senior Vice President, Safety & Chief People Officer

Gregory C. Hesler, 48
Senior Vice President, General Counsel, Corporate Secretary & Chief Ethics/Compliance Officer

Wayne O. Manuel, 53
Senior Vice President, Operations & Technology

Jason R. Thackston, 56
Senior Vice President, Growth, Energy Policy & External Relations

Alexis G. Alexander, 43
Vice President, Chief Information & Chief Security Officer

Joshua D. DiLuciano, 45
Vice President, Energy Delivery

Latisha D. Hill, 47
Vice President, Community Affairs & Chief Customer Officer

Scott J. Kinney, 57
Vice President, Energy Resources & Integrated Planning

Ryan L. Krasselt, 56
Vice President, Controller & Principal Accounting Officer

David J. Meyer, 72
Vice President & Chief Counsel for Regulatory & Governmental Affairs

Alec J. Mesdag, 46
President & CEO, Alaska Electric Light & Power Co.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED **DECEMBER 31, 2025** OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM ________________ TO ________________

Commission file number 001-03701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

WA	91-0462470
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1411 East Mission Avenue, Spokane, WA 99202-2600
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: 509-489-0500
Website: http://www.avistacorp.com

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock	AVA	NYSE

Securities registered pursuant to Section 12(g) of the Act:

Title of Class
Preferred Stock, Cumulative, Without Par Value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days: Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer	☒	Accelerated Filer	☐	Non-accelerated Filer	☐
Smaller reporting company	☐	Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act):
Yes ☐ No ☒

The aggregate market value of the Registrant's outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $3,078,099,757 based on the last reported sale price thereof on the consolidated tape on June 30, 2025.

As of January 31, 2026, 82,251,245 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

Documents Incorporated By Reference

Document	Part of Form 10-K into Which Document is Incorporated
Proxy Statement to be filed in connection with the annual meeting of shareholders to be held May 14, 2026. Prior to such filing, the Proxy Statement was filed in connection with the annual meeting of shareholders held on May 8, 2025.	Part III, Items 10, 11, 12, 13 and 14

INDEX

PART I

PART II

INDEX (continued)

** = not an applicable item in the 2025 calendar year for Avista Corp.*

ACRONYMS AND TERMS

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
aMW	– Average Megawatt—a measure of the average rate at which a particular generating source produces energy over a period of time
AEL&P	– Alaska Electric Light and Power Company, the primary operating subsidiary of AERC, which provides electric services in Juneau, Alaska
AERC	– Alaska Energy and Resources Company, the Company's wholly owned subsidiary based in Juneau, Alaska
AFUDC	– Allowance for Funds Used During Construction, represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
ASC	– Accounting Standards Codification
Avista Capital	– Parent company to the Company's non-utility businesses, with the exception of AJT Mining Properties, Inc., which is a subsidiary of AERC.
Avista Corp.	– Avista Corporation, the Company
Avista Utilities	– Operating division of Avista Corp. (not a subsidiary) comprising the regulated utility operations in Washington, Idaho, Oregon and Montana
BPA	– Bonneville Power Administration
Capacity	– The rate at which a particular generating source is capable of producing energy, measured in kW or MW
Cabinet Gorge	– The Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
CCA	– Climate Commitment Act, Washington
CCRs	– Coal Combustion Residuals, also termed coal combustion byproducts or coal ash
CEIP	– Clean Energy Implementation Plan, Washington
CETA	– Clean Energy Transformation Act, Washington
CPP	– Climate Protection Program, Oregon
Colstrip	– The coal-fired Colstrip Generating Plant in southeastern Montana
Cooling degree days	– The measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day is above 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures)
Coyote Springs 2	– The natural gas-fired combined-cycle Coyote Springs 2 Generating Plant located near Boardman, Oregon
CT	– Combustion turbine
Deadband or ERM deadband	– The first $4 million in annual power supply costs above or below the amount included in base retail rates in Washington under the ERM in the state of Washington
Ecology	– The Washington State Department of Ecology

ACRONYMS AND TERMS (continued)

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
EIM	– Energy Imbalance Market
Energy	– The amount of electricity produced or consumed over a period of time, measured in kWh or MWh. Also, refers to natural gas consumed and is measured in dekatherms.
EPA	– Environmental Protection Agency
ERM	– The Energy Recovery Mechanism, a mechanism for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Washington
FCA	– Fixed Cost Adjustment, the electric and natural gas decoupling mechanism in Idaho.
FERC	– Federal Energy Regulatory Commission
FPA	– Federal Power Act
GAAP	– Generally Accepted Accounting Principles
GHG	– Greenhouse gas
GS	– Generating station
Heating degree days	– The measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day is below 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures)
IPUC	– Idaho Public Utilities Commission
IRP	– Integrated Resource Plan
Jackson Prairie	– Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington
kV	– Kilovolt (1000 volts): a measure of capacity on transmission lines
kW, kWh	– Kilowatt (1000 watts): a measure of generating output or capability. Kilowatt-hour (1000 watt hours): a measure of energy produced
Lancaster Plant	– A natural gas-fired combined cycle combustion turbine plant located in Idaho
mmBTU	– One million British Thermal Units, a thermal unit of measurement for natural gas
MPSC	– Public Service Commission of the State of Montana
MW, MWh	– Megawatt: 1000 kW. Megawatt-hour: 1000 kWh
MYRP	– Multi-year rate plan
NERC	– North American Electricity Reliability Corporation
NorthWestern	– NorthWestern Corporation

ACRONYMS AND TERMS (continued)

(The following acronyms and terms are found in multiple locations within the document)

Acronym/Term	Meaning
Noxon Rapids	– The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OPUC	– The Public Utility Commission of Oregon
PCA	– The Power Cost Adjustment mechanism, a procedure for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Idaho
PGA	– Purchased Gas Adjustment
PPA	– Power Purchase Agreement
PUD	– Public Utility District
RCA	– The Regulatory Commission of Alaska
REC	– Renewable energy credit
ROE	– Return on equity
ROR	– Rate of return on rate base
ROU	– Right-of-use lease asset
SEC	– U.S. Securities and Exchange Commission
Talen	– Talen Montana, LLC, an indirect subsidiary of Talen Energy Corporation.
Therm	– Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
WUTC	– Washington Utilities and Transportation Commission

FORWARD-LOOKING STATEMENTS

From time-to-time, we make forward-looking statements such as statements regarding projected or future:

- financial performance;
- cash flows;
- capital expenditures;
- dividends;
- capital structure;
- other financial items;
- strategic goals and objectives;
- business environment; and
- plans for operations.

These statements are based upon underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Annual Report on Form 10-K), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those identified by the use of words that include "will," "may," "could," "should," "intends," "plans," "aspires," "assumes," "targets," "seeks," "anticipates," "estimates," "expects," "forecasts," "projects," "predicts," and similar expressions.

Forward-looking statements (including those made in this Annual Report on Form 10-K) are subject to a variety of risks, uncertainties and other factors. Most of these factors are beyond our control. Any of these factors may have a significant effect on our operations, results of operations, financial condition or cash flows, and could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

Utility Regulatory Risk

- state and federal regulatory decisions or related judicial decisions that affect our ability to recover costs and earn a reasonable return, including, but not limited to, disallowance or delay in the recovery of capital investments, operating costs, commodity costs, the ordering of refunds to customers and discretion over allowed return on investment;
- the loss of regulatory accounting treatment, which could require the write-off of regulatory assets and the loss of regulatory deferral and recovery mechanisms;

Operational Risk

- weather conditions, which affect both energy demand and electric generating capability, including the impact of precipitation and temperature on hydroelectric resources, the impact of wind patterns on wind-generated power, weather-sensitive customer demand, and similar impacts on supply and demand in the wholesale energy markets;
- wildfires ignited, or allegedly ignited, by our equipment or facilities could cause significant loss of life and property or result in liability for resulting fire suppression costs and/or damages, thereby causing serious operational, reputational and financial harm;
- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, floods, extreme temperature events, snow and ice storms that could disrupt energy generation, transmission and distribution, as well as the availability and costs of fuel, materials, equipment, supplies and support services;
- political unrest and/or conflicts between foreign nation-states, which could disrupt the global, national and local economy, result in increases in operating and capital costs, impact energy commodity prices or our ability to access energy resources, create disruption in supply chains, disrupt, weaken or create volatility in capital markets, and increase cyber and physical security risks. In addition, any of these factors could negatively impact our liquidity and limit our access to capital, among other implications;
- explosions, fires, accidents, mechanical breakdowns or other incidents that could impair assets and may disrupt operations of our generation facilities, transmission, and electric and natural gas distribution systems or other operations and may require us to purchase replacement power or incur costs to repair our facilities;
- interruptions in the delivery of natural gas by our suppliers, including physical problems with pipelines themselves, can disrupt our service of natural gas to our customers and/or impair our ability to operate gas-fired electric generating facilities;
- explosions, fires, accidents or other incidents arising from or allegedly arising from our operations that could cause injuries to the public or property damage;
- dam failure at a company-owned hydroelectric facility;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- terrorist attacks, cyberattacks or other malicious acts that could disrupt or cause damage to our utility assets or to the national or regional economy in general, including effects of terrorism, cyberattacks, ransomware, or vandalism that damage or disrupt information technology systems;
- pandemics, which could disrupt our business, as well as the global, national and local economy, resulting in a decline in customer demand, deterioration in the creditworthiness of our customers, increases in operating and capital costs, workforce shortages, losses or disruptions in our workforce due to vaccine mandates, delays in capital projects, disruption in supply chains, and disruption, weakness and volatility in capital markets. In addition, any of these factors could negatively impact our liquidity and limit our access to capital, among other implications;
- work-force issues, including changes in collective bargaining unit agreements, strikes, work stoppages, the loss of key executives, availability of workers in a variety of skill areas, and our ability to recruit and retain employees;
- changes in the availability and price of purchased power, fuel and natural gas, as well as transmission capacity;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- increasing health care costs and cost of health insurance provided to our employees and retirees;
- increasing operating costs, including effects of inflationary pressures;

- third party construction of buildings, billboard signs, towers or other structures within our rights of way, or placement of fuel containers within close proximity to our transformers or other equipment, including overbuilding atop natural gas distribution lines;
- the loss of key suppliers for materials or services or other disruptions to the supply chain;
- adverse impacts to our Alaska electric utility (AEL&P) that could result from an extended outage of its hydroelectric generating resources or their inability to deliver energy, due to their lack of interconnectivity to other electrical grids and the availability or cost of replacement power (diesel);
- changing river or reservoir regulation or operations at hydroelectric facilities not owned by us, which could impact our hydroelectric facilities downstream;

Climate Change Risk

- increasing frequency and intensity of severe weather or natural disasters resulting from climate change that could disrupt energy generation, transmission and distribution, as well as the availability and costs of fuel, materials, equipment, supplies and support services;
- change in the use, availability or abundancy of water resources and/or rights needed for operation of our hydroelectric facilities, including impacts resulting from climate change;
- changes in the long-term climate and weather could materially affect, among other things, customer demand, the volume and timing of streamflows required for hydroelectric generation, costs of generation, transmission and distribution. Increased or new risks may arise from severe weather or natural disasters, including wildfires as well as their increased occurrence and intensity related to changes in climate;

Cybersecurity Risk

- cyberattacks on the operating systems used in the operation of our electric generation, transmission and distribution facilities and our natural gas distribution facilities, and cyberattacks on such systems of other energy companies with which we are interconnected, which could damage or destroy facilities or systems or disrupt operations for extended periods of time and result in the incurrence of liabilities and costs;
- cyberattacks on the administrative systems used in the administration of our business, including customer billing and customer service, accounting, communications, compliance and other administrative functions, and cyberattacks on such systems of our vendors and other companies with which we do business, resulting in the disruption of business operations, the release of private information and the incurrence of liabilities and costs;

Technology Risk

- changes in technologies, possibly making some of the current technology we utilize obsolete or introducing new cybersecurity risks and other new risks inherent in the use, by either us or our counterparties, of new technologies in the developmental stage including, without limitation, generative artificial intelligence;
- changes in the use, perception, or regulation of generative artificial intelligence technologies, which could limit our ability to utilize such technology, create risk of enhanced regulatory scrutiny, generate uncertainty around intellectual property ownership, licensing or use, or which could otherwise result in risk of damage to our business, reputation or financial results;
- changes in costs that impede our ability to implement new information technology systems or to operate and maintain current production technology;
- insufficient technology skills, which could lead to the inability to develop, modify or maintain our information systems;

Strategic Risk

- growth or decline of our customer base due to new uses for our services or decline in existing services, including, but not limited to, the effect of the trend toward distributed generation at customer sites;
- the potential effects of negative publicity regarding our business practices, whether true or not, which could hurt our reputation and result in litigation or a decline in our common stock price;
- changes in our strategic business plans, which could be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses and the extent of our business development efforts where potential future business is uncertain;
- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- non-regulated activities may increase earnings volatility and result in investment losses;
- the risk of municipalization or other forms of service territory reduction;

External Mandates Risk

- changes in environmental laws, regulations, decisions and policies, including, but not limited to, regulatory responses to concerns regarding climate change, efforts to restore anadromous fish in areas currently blocked by dams, more stringent requirements related to air quality, water quality and waste management, present and potential environmental remediation costs and our compliance with these matters;
- the potential effects of initiatives, legislation or administrative rulemaking at the federal, state or local levels, including possible effects on our generating resources, prohibitions or restrictions on new or existing services, or restrictions on greenhouse gas emissions to mitigate concerns over climate changes, including future limitations on the usage and distribution of natural gas;
- restrictions or changes in government grant programs and/or availability of other public funding used for capital projects;
- political pressures or regulatory practices that could constrain or place additional cost burdens on our distribution systems through accelerated adoption of distributed generation or electric-powered transportation or on our energy supply sources, such as campaigns to halt fossil fuel-fired power generation and opposition to other thermal generation, wind turbines or hydroelectric facilities;
- failure to identify changes in legislation, taxation and regulatory issues that could be detrimental or beneficial to our overall business;

- policy and/or legislative changes in various regulated areas, including, but not limited to, environmental regulation, healthcare regulations and import/export regulations;
- increasing costs due to potential tariffs applied to energy commodities and/or equipment and materials;

Financial Risk

- our ability to obtain financing through the issuance of debt and/or equity securities and access to our funds held with financial institutions, which could be affected by various factors including our credit ratings, interest rates, other capital market conditions and global economic conditions;
- changes in interest rates that affect borrowing costs, variable interest rate borrowing and the extent to which we recover interest costs through retail rates collected from customers;
- volatility in energy commodity markets that affects our ability to effectively hedge energy commodity risks, including cash flow impacts and requirements for collateral;
- volatility in the carbon emissions allowances market that could result in increased compliance costs;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement benefit plans, which could affect future funding obligations, pension and other postretirement benefit expense and the related liabilities;
- the outcome of legal proceedings and other contingencies;
- economic conditions in our service areas, including the economy's effects on customer demand for utility services;
- economic conditions nationally may affect the valuation of our unregulated portfolio companies;
- declining electricity demand related to customer energy efficiency, conservation measures and/or increased distributed generation and declining natural gas demand related to customer energy efficiency, conservation measures and/or increased electrification;
- industry and geographic concentrations which could increase our exposure to credit risks due to counterparties, suppliers and customers being similarly affected by changing conditions;
- deterioration in the creditworthiness of our customers;
- activist shareholders may result in additional costs and resources required in response to activist actions;

Energy Commodity Risk

- volatility and illiquidity in wholesale energy markets, including exchanges, the availability of willing buyers and sellers, changes in wholesale energy prices that could affect operating income, cash requirements to purchase electricity and natural gas, value received for wholesale sales, collateral required of us by individual counterparties and/or exchanges in wholesale energy transactions and credit risk from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of parties from whom we purchase and/or sell capacity or energy;
- potential environmental regulations or lawsuits affecting our ability to utilize or resulting in the obsolescence of our power supply resources;
- explosions, fires, accidents, pipeline ruptures or other incidents that could limit energy supply to our facilities or our surrounding territory, which could result in a shortage of commodities in the market that could increase the cost of replacement commodities from other sources;

Compliance Risk

- changes in laws, regulations, decisions and policies at the federal, state or local levels, which could materially impact both our electric and gas operations and costs of operations;
- the ability to comply with the terms of the licenses and permits for our hydroelectric or thermal generating facilities at cost-effective levels;

Resource Adequacy Risk

- the ability to source and deliver adequate energy to meet customer demand in periods of high demand or unplanned events; and
- the potential effects of regional wholesale market strains, including during extreme weather events.

Our expectations, beliefs and projections are expressed in good faith. We believe they are reasonable based on, without limitation, an examination of historical operating trends, our records and other information available from third parties. However, there can be no assurance that our expectations, beliefs or projections will be achieved. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New risks, uncertainties and other factors emerge from time-to-time, and it is not possible to predict all such factors, nor can we assess the effect of each such factor on our business or the extent that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

AVAILABLE INFORMATION

We file annual, quarterly and current reports and proxy statements with the SEC. The SEC maintains a website that contains these documents at www.sec.gov. We make annual, quarterly and current reports and proxy statements available on our website, https://investor.avistacorp.com, as soon as practicable after electronically filing these documents with the SEC. Except for SEC filings or portions thereof specifically referred to in this report, information contained on these websites is not part of this report.

PART I

ITEM 1. BUSINESS

COMPANY OVERVIEW

Avista Corp., incorporated in the territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. Our corporate headquarters is in Spokane, Washington, the second-largest city in Washington. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region (eastern Washington and northern Idaho). Regional services include government and higher education, medical services, retail trade and finance. Through our subsidiary AEL&P, we also provide electric utility services in Juneau, Alaska.

As of December 31, 2025, we have two reportable business segments as follows:

- **Avista Utilities**—an operating division of Avista Corp., comprising the regulated utility operations in Washington, Idaho, Oregon and Montana. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and its load-serving obligation.
- **AEL&P**—a regulated utility providing electric services in Juneau, Alaska that is a wholly owned subsidiary and the primary operating subsidiary of AERC.

We have other businesses, including venture fund investments, real estate investments, as well as certain other investments made by Avista Capital, which is a direct, wholly owned subsidiary of Avista Corp. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp.

Total Avista Corp. shareholders' equity was $2.7 billion as of December 31, 2025, which includes a $126 million investment in Avista Capital and a $129 million investment in AERC.

See "Note 24 of the Notes to Consolidated Financial Statements" for information with respect to the operating performance of each business segment (and other subsidiaries).

Human Capital

On December 31, 2025, Avista Utilities employed 1,929 individuals with bargaining unit employees comprising 36 percent of our overall workforce.

Our approach to people is a critical strategy to inspire engaged and thriving employees by empowering a high-performing organization where employees are valued, respected and have opportunities to grow. Among other things, this strategy supports hiring talented people and equipping them with capabilities, tools and a culture that empowers them to pursue great ideas. Such ideas engage the imagination, stretch us all as we continue to provide exemplary and cost-effective service to our customers. Focus areas for this strategy strive to:

- improve employee engagement, belonging, equity, attraction and retention while building a sense of community and purpose,
- support safety and well-being through innovative programs, best practices, tools, and technology, and
- expand innovation disciplines, capabilities, and mindsets with cross-departmental interactions and external networks to build the utility of the future.

The following is an overview of some of our key human capital initiatives intended to inspire engaged and thriving employees and other stakeholders, such as our customers and business partners.

Employee Attraction, Development and Retention

We strive to hire and retain talented people who are innovative and skilled so we can continue to provide safe, reliable and affordable service to our customers and advance the Company at the same time. We are focused on innovative recruiting and educational outreach to organizations and schools to create greater awareness of the variety of career opportunities available in our industry and in the Company. We continue to think creatively about how we connect with our communities regarding employment opportunities, with a goal of attracting talented individuals who can help advance the Company's objectives.

All of our collective bargaining agreements are with local chapters of the International Brotherhood of Electrical Workers (IBEW). In 2025, the Company successfully negotiated a 4-year agreement for our largest collective bargaining agreement. In 2026, we have one agreement expiring and currently under negotiation for a successor contract, along with negotiations for a newly-organized bargaining unit. The partnership with IBEW is key to a holistic approach to employee attraction, engagement, and retention.

Continuous learning plays a large part in fostering collaboration and innovation among our employees and is pervasive throughout the Company. Development opportunities are created to prepare our employees at all levels to continue building their skills, knowledge and experience to perform today and in the future. Keeping our workforce equipped to succeed is imperative to meet the emerging challenges that lie ahead. We develop training that is relevant, necessary and in demand for our organization. Training is delivered through instructor-led courses, self-service topics, computer-based learning modules, and field-based, hands-on workshop models covering the range of our operations. Training programs include craft apprenticeship programs, engineering development programs, leadership development, communication skills, cross-functional learning and other topics. We also provide opportunities for our employees to attend industry events and certification programs, courses or programs offered through energy-related organizations such as the Western Energy Institute, the American Gas Association and the Edison Electric Institute, as well as through our local colleges and universities.

Competitive pay and benefits, or total rewards, are a key component of our strategy to attract and retain talented employees. The Company is committed to equitable and market-competitive compensation and has well-established practices to create competitive offers, reward performance, and support employee retention. The Company regularly monitors the benefits market and manages benefit costs through a comprehensive program that supports our employees' physical, mental, and financial well-being.

In 2025, we conducted our biennial employee experience survey. The purpose of this survey is to provide employees at all levels of the organization with an opportunity to confidentially share their perspectives about their experiences working at Avista Corp., our workplace culture, and topics such as autonomy, enablement, growth opportunities, connection, leadership, safety, engagement and belonging, etc. The Company conducted many listening sessions to learn more about our employee needs and gain a better understanding of what actions might be taken to improve the employee experience.

Workplace Safety

Safety and well-being are an essential part of our Company's mission and a key strategy to support our employees through innovative programs, best practices, tools and technology. A variety of programs and initiatives are in place to help employees complete their work safely through heightened vigilance, hazard recognition, defensive strategies, lessons learned, human and organizational performance and other tools intended to strengthen resilience in varying and unpredictable conditions. We work with our employees to reinforce personal responsibility regarding safety and health, and to implement measures to create and maintain a safe work environment.

AVISTA UTILITIES

General

At the end of 2025, Avista Utilities supplied retail electric service to approximately 429,000 customers and retail natural gas service to approximately 386,000 customers across its service territory. Avista Utilities' service territory covers 34,000 square miles with a population of 1.5 million.

Electric Operations

General

Avista Utilities generates, transmits and distributes electricity, serving electric customers in eastern Washington and northern Idaho and a small number of customers in Montana.

Avista Utilities generates electricity from facilities that we own and purchases capacity, energy and fuel for generation under long-term and short-term contracts to meet customer load obligations. We also sell electric capacity and energy, as well as surplus fuel in the wholesale market in connection with our resource optimization activities as described below.

As part of Avista Utilities' resource procurement and management operations in the electric business, we engage in an ongoing process of resource optimization, which involves the selection from available energy resources to serve our load obligations and the use of these resources to capture economic value through wholesale market transactions. These include sales and purchases of electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy, fuel and fuel transportation. Such transactions are part of the process of matching available resources with load obligations and hedging a portion of the related financial risks.

To implement this process, we make continuing projections of:

- electric loads at various points in time (ranging from intra-hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data, contract terms, and emerging trends and climate modeling results,
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of snowpack and streamflows, availability of generating units, historic and forward market information, contract terms and our experience, and
- carbon allowance costs and other emission fees associated with emission reduction legislation and policy.

Based on these projections, we make purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative contracts to match expected resources to expected electric load requirements and reduce our exposure to electricity (or fuel) market price changes. The process of resource optimization involves scheduling and dispatching available resources as well as the following:

- purchasing fuel for generation,
- when economical, selling fuel and substituting wholesale electric purchases, and
- other wholesale transactions to capture the value of generating resources, transmission contract rights and fuel delivery (transport) capacity contracts.

This optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative instruments, and the terms range from intra-hour up to multiple years.

Avista Utilities' generation assets are interconnected through the regional transmission system and are operated on a coordinated basis to enhance load-serving capability and reliability. We acquire both long-term and short-term transmission capacity to facilitate our energy and capacity transactions. We provide transmission and ancillary services in eastern Washington, northern Idaho and western Montana.

Peak Electric Requirements

Avista Utilities' peak electric native load requirement for 2025 was 1,837 MW, which occurred on September 2, 2025. In 2024, our peak electric native load was 1,869 MW, which occurred during the winter, and in 2023, it was 1,809 MW, which occurred during the summer.

Electric Resources

Avista Utilities has a diverse electric resource mix of Company-owned and contracted hydroelectric, thermal, wind and solar generation facilities, and other contracts for power purchases and exchanges. As of December 31, 2025, Avista Utilities' electric generation resource mix (including contracts for power purchases) was approximately 48 percent hydroelectric, 37 percent thermal and 15 percent other renewables. On January 1, 2026, the Company transferred its ownership in Colstrip to NorthWestern, resulting in a generation resource mix (including contracts for power purchases) of approximately 53 percent hydroelectric, 32 percent thermal and 15 percent other renewables. See "Item 2. Properties" for detailed information on Company-owned generating facilities and a detailed list of our PPAs.

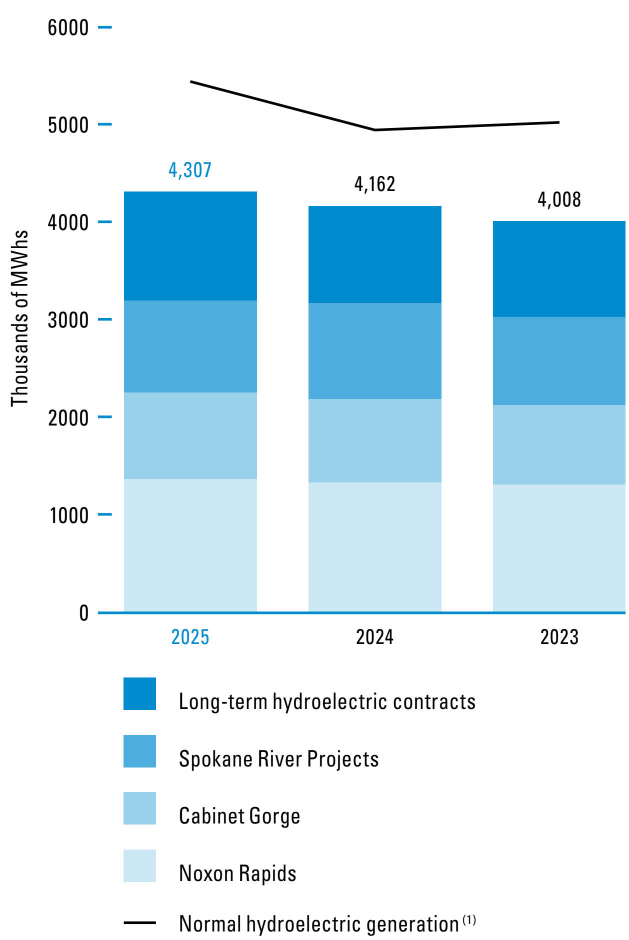
Hydroelectric Resources

Avista Utilities owns and operates Noxon Rapids and Cabinet Gorge on the Clark Fork River and six smaller hydroelectric projects on the Spokane River. Hydroelectric generation is typically our lowest cost source per MWh of electric energy and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, we estimate that we would be able to meet approximately one-half of our total average electric requirements (both retail and long-term wholesale) with the combination of our hydroelectric generation and long-term hydroelectric purchase contracts (including those with certain PUDs in the state of Washington and Columbia Basin Hydropower). Normal and actual annual hydroelectric generation increased in 2025 as a result of increased output received from additional capacity under one of our PPA contracts. Our estimate of normal annual hydroelectric generation for 2026 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 648.3 aMW (or 5.68 million MWhs).

See "Item 2. Properties—Avista Utilities" for the present generating capabilities of the above hydroelectric resources.

The following graph shows Avista Utilities' hydroelectric generation (in thousands of MWhs) during the year ended December 31:

HYDROELECTRIC GENERATION



(1) Normal hydroelectric generation is determined by reference to the effect of upstream dam regulation on median natural water flow. Natural water flow is the flow of the rivers without the influence of dams, whereas regulated water flow reflects water flow changes from upstream dams due to releasing or holding back water. The calculation of normal varies annually due to the timing of upstream dam regulation throughout the year, as well as changes in PUD contracts.

Thermal Resources

Avista Utilities owns the following thermal generating resources:

- the combined cycle natural gas-fired CT, known as Coyote Springs 2, located near Boardman, Oregon,
- a wood waste-fired boiler generating facility known as the Kettle Falls GS in northeastern Washington,
- a two-unit natural gas-fired CT generating facility in northeastern Spokane (Northeast CT),
- a two-unit natural gas-fired CT generating facility in northern Idaho (Rathdrum CT), and
- two small natural gas-fired generating facilities (Boulder Park GS and Kettle Falls CT).

Coyote Springs 2, which is operated by Portland General Electric Company, is supplied with natural gas under a combination of term contracts and spot market purchases, including transportation agreements with bilateral renewal rights.

The primary fuel for the Kettle Falls GS is wood waste generated as a by-product and delivered by trucks from forest industry operations within 100 miles of the plant. A combination of long-term contracts and spot purchases has provided, and is expected to meet, fuel requirements for the Kettle Falls GS.

The Northeast CT, Rathdrum CT, Boulder Park GS and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. We also operate these facilities when marginal costs are below prevailing wholesale electric prices. These generating facilities have access to natural gas supplies that are adequate to meet their respective operating needs.

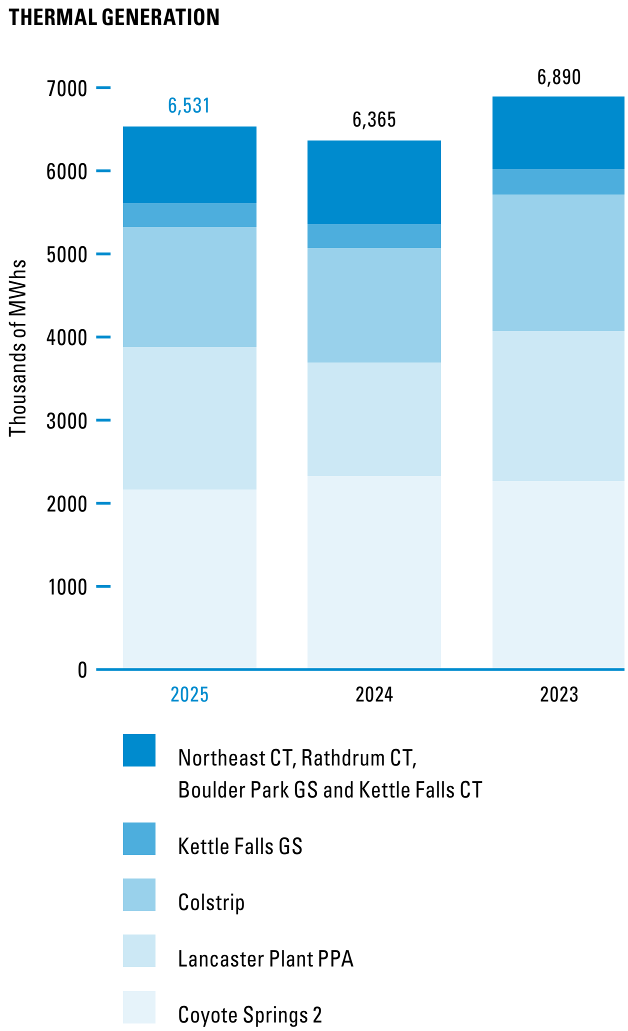
We previously held a 15 percent interest in Units 3 & 4 of Colstrip, a coal-fired generating facility located in southeastern Montana. We transferred our ownership interest to NorthWestern on January 1, 2026. See "Item 7. Management's Discussion and Analysis—Colstrip" and "Note 22 of the Notes to Consolidated Financial Statements" for discussion regarding environmental and other issues surrounding Colstrip.

In addition to the resources we own listed above, we have a PPA for the output from the Lancaster Plant through December 31, 2041. The Lancaster Plant is a 270 MW natural gas-fired combined cycle combustion turbine plant located in northern Idaho, owned by an unrelated third-party. Under the terms of the PPA, we make the dispatch decisions, provide all natural gas fuel and receive all electric energy output. Therefore, we consider the Lancaster Plant to be a baseload resource. See "Note 5 of the Notes to Consolidated Financial Statements" for further discussion of this PPA.

See "Natural Gas Operations—Natural Gas Supply" for information regarding our supply of natural gas for both fuel and delivery to natural gas customers.

See "Item 2. Properties—Avista Utilities" for the present generating capabilities of the above thermal resources.

The following graph shows Avista Utilities' thermal generation (in thousands of MWhs) during the year ended December 31:



Wind Resources

We have exclusive rights to the capacity of Palouse Wind, a wind generation project developed, owned and managed by an unrelated third-party and located in Whitman County, Washington. Under the PPA, we purchase the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. We have an annual option to purchase the wind project, which we have not exercised. The purchase price is a fixed price per kW of in-service capacity with a fixed decline in the price per kW over the remaining term of the PPA.

We have exclusive rights to the capacity of Rattlesnake Flat Wind project developed, owned and managed by an unrelated third party and located in Adams County, Washington. We purchase the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement.

See "Item 2. Properties" for a detailed list of our PPAs.

Solar Resources

We have exclusive rights to the capacity of the Lind Solar Farm, a solar generation project developed, owned and managed by an unrelated third-party and located in Lind, Washington. Under a PPA, we purchase the power and renewable attributes produced by the project at a fixed price per MWh.

See "Item 2. Properties" for a detailed list of our PPAs.

Other Purchases, Exchanges and Sales

In addition to the resources described above, we purchase and sell power under various long-term contracts, and we enter into short-term purchases and sales. Further, pursuant to The Public Utility Regulatory Policies Act of 1978, as amended, we are required to purchase generation from qualifying facilities. This includes, among other resources, hydroelectric projects, cogeneration projects and wind generation projects at rates approved by the WUTC and the IPUC.

See "Avista Utilities Electric Operating Statistics—Electric Operations" below for annual quantities of purchased power, wholesale power sales and power from exchanges in 2025, 2024 and 2023. See "Electric Operations" above for additional information on the use of wholesale purchases and sales as part of our resource optimization process and see "Future Resource Needs" below for the magnitude of these power purchase and sales contracts in future periods.

Regional Capacity Issues

The northwest region is experiencing increased load growth, more frequent extreme weather events, and a transition to more variable energy resources. Both the region's electric and natural gas delivery systems are also reaching full utilization during peak load conditions. Purchases of capacity and energy at any time are dependent upon the availability of excess capacity in the west region at that time. Many coal-fired electric generating stations throughout the western United States are scheduled for retirement in the next several years. Depending upon a variety of factors, these retirements could have an impact upon the availability and price of purchased power in, and the dynamics of, the market in which we conduct our wholesale purchases and sales. After December 31, 2025, we are prohibited by the Clean Energy Transformation Act (CETA) from using energy produced by coal-fired plants to serve our retail customers in Washington (with some exceptions for coal generated short-term purchases), and we transferred our interest in Colstrip to NorthWestern on January 1, 2026. To the extent necessary, we will obtain energy produced by other regional resources. See "Item 7. Management's Discussion and Analysis—Environmental Matters and Contingencies—Climate Change—Washington Legislation and Regulatory Actions—Clean Energy Transformation Act" and "Colstrip."

In addition to the retirement of coal-fired generating stations, some hydroelectric and other generation plants in the region are being considered for possible closure due to environmental and other concerns. The reduction of regional generating capacity will have to be offset by the addition of new generating resources and energy storage facilities.

Hydroelectric Licenses

Avista Corp. is a licensee under the FPA as administered by the FERC, which includes regulation of hydroelectric generation resources. Excluding the Little Falls Hydroelectric Generating Project (Little Falls), our other seven hydroelectric plants are regulated by the FERC through two project licenses.

Cabinet Gorge and Noxon Rapids are under one 45-year FERC license expiring in 2046. This license embodies a settlement agreement relating to project operations and resource protection and mitigation efforts over the license term.

Five of our six hydroelectric projects on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls) are under one 50-year FERC license expiring in 2059 and are referred to collectively as the Spokane River Project. The license includes numerous natural and cultural resource protection measures that are subject to ongoing regulatory interpretation. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. It is the subject of a 50-year agreement with the Spokane Tribe, expiring in 2044.

The FERC grants hydroelectric licenses, and relicenses, only after a multi-year process involving public hearings and input from multiple federal, state and local government agencies, tribes, non-governmental organizations, private landowners and other stakeholders. The FERC must find that the proposed project will be best adapted to a comprehensive plan for the waterway, taking into account the needs of power development, fish and wildlife, irrigation, flood control, water supply, recreation and other competing uses, and licenses (and relicenses) must be conditioned on appropriate protection, mitigation and enhancement measures.

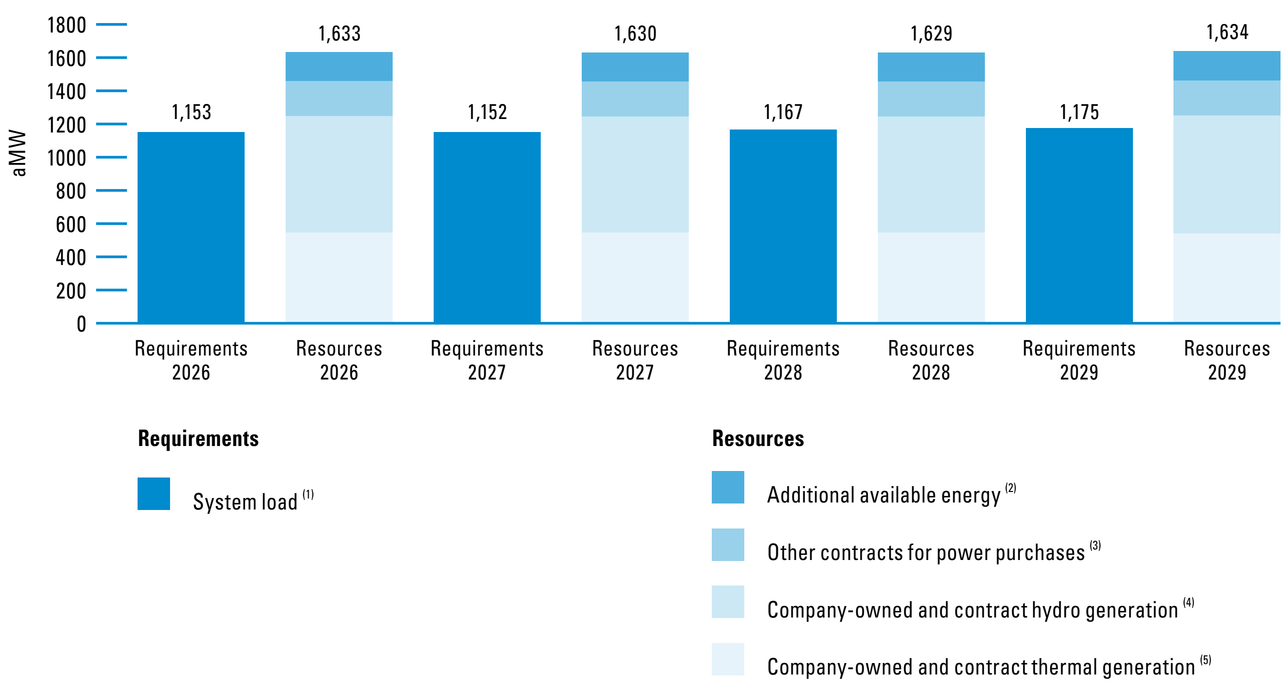
Generally, upon the expiration of a license, (1) the FERC could grant a new licenses upon terms determined at that time, (2) the United States could take over the project, or the FERC could issue a new license to a new licensee, upon payment to the licensee of the lesser of the licensee's "net investment" in, or the "fair value" of, the project, plus severance damages, or (3) under the FERC's interpretation of the FPA, the FERC could order the decommissioning of the project. There is no assurance that any existing license will be renewed upon its expiration or, if renewed, that the renewal would be without significant modifications.

Future Electric Resource Needs

Avista Utilities has operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed, which varies because of the factors that influence demand over intra-hour, hourly, daily, monthly and annual durations. Our average hourly load was 1,149 aMW in 2025, 1,117 aMW in 2024 and 1,115 aMW in 2023.

The following graph shows our forecasted average annual energy requirements (in aMWs) and our available resources (in MWs) for 2026 through 2029:

FORECASTED ELECTRIC ENERGY REQUIREMENTS AND RESOURCES



(1) Forecast system load does not include the addition of large load customers, which could increase system load and require additional resources, as contemplated in our 2025 Electric IRP.

(2) Estimated available energy production from Company-owned Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT resources.

(3) Other contracts for power purchases include power purchase agreements for solar and wind energy.

(4) The forecast assumes near normal hydroelectric generation.

(5) Includes the Lancaster Plant PPA. Excludes Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT, as these are considered peaking facilities and are generally not used to meet our base load requirements.

We are required to file an Integrated Resource Plan (IRP) or Washington Progress Report with the WUTC and IPUC every two years. The WUTC and IPUC review the IRP and give the public the opportunity to comment. The WUTC and IPUC do not approve or disapprove of the content in the IRP; rather, they acknowledge that the IRP was prepared in accordance with applicable standards if that is the case. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

In December 2024, we filed our 2025 Electric IRP with the WUTC and the IPUC.

Highlights of the 2025 Electric IRP include the following expectations and/or assumptions:

- Due to customer growth and loss of capacity resources, the Company will need to acquire additional electricity generation to serve peak loads. Our preferred resource strategy calls for the addition of approximately 490 MW of generating capacity by 2030 and a total of approximately 950 MW to be added through 2035.
- Customer energy demand is expected to grow an average of 0.9 percent per year over the next 20 years and an average of winter peak demand by 1.12 percent per year over the next 20 years.
- The 66 MW Northeast CT will be retired in 2030.
- Energy efficiency reduces future demand growth by 32 percent over 20 years.
- Demand response programs reduce peak demand by up to 4 percent.
- Identifies the proposed North Plains Connector transmission line as a preferred resource alternative along with other transmission upgrades in the Inland Northwest.
- We are projected to exceed CETA's requirements to be greenhouse gas neutral with Washington's electric supply by 2030.
- Meeting CETA's 2045 targets will require significant energy transformation including maintaining our existing hydroelectric system and acquiring new energy resources which could include using hydrogen-based fuels, wind, solar and nuclear, and will include long-term energy storage.

2025 Request for Proposal (RFP)

In May 2025, we issued an RFP requesting bids for up to 425 MW of capacity resources to meet modeled load growth needs and anticipated new large loads. See further information on the RFP within "Item 7. Management's Discussion and Analysis—Executive Overview".

Additional generating resources required will either be owned by us or be owned by other parties who will sell us the capacity and energy under PPAs. The decision as to ownership will be made as to each project at the appropriate time and will depend on, among other things, the type of project and the related economics, including tax and ratemaking treatment.

We are subject to the Washington State Energy Independence Act, which requires us to obtain a portion of our electricity from qualifying renewable resources or through purchase of RECs and acquiring all cost effective energy efficiency measures. Future generation resource decisions will be affected by legislation for restrictions on greenhouse gas emissions and renewable energy requirements.

See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for information related to existing and proposed laws and regulations that impact our resource availability.

Electric Clean Energy Goals

We have an aspirational goal to serve our customers with 100 percent clean electricity by 2045. To help achieve this goal and add to our clean electricity portfolio, we have implemented renewable energy projects, including entering into various PPAs for solar, wind and hydroelectric resources. These resources are in addition to our existing clean hydroelectric generation, biomass generation, and additional wind and solar projects.

To achieve our clean energy goals, we expect energy storage and other technologies, which are either not currently available or are not cost-effective under the lowest reasonable cost regulatory standard, will advance to allow us to meet our goals while maintaining reliability and affordability for our customers. If the required technology is not available or not affordable in the future, we may not meet our goals in the desired timeframe. Meeting our clean energy goals may also require accommodation from regulatory agencies. See the discussion under "Electric Resources" for more information on our existing clean electricity sources and efforts to achieve these goals. See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion on clean energy, including applicable regulations.

Wildfire Resiliency Plan

We have a wildfire resiliency plan focused on four primary areas: transmission and distribution system hardening, enhanced vegetation management, situational awareness, and operations and response.

Grid hardening involves investing in electric infrastructure to reduce spark-ignition outage events and to protect critical assets from the impact of wildfires at the distribution level, including replacing wood crossarms with fiberglass, replacing small wire, adding protective devices, undergrounding, and more. We also invest at the transmission level, replacing wood poles with steel or wrapping them with a fire-resistant protective cover in high fire risk areas. We are also developing an enhanced grid hardening program which may involve undergrounding high fire risk sections of the distribution system.

Enhanced vegetation management involves risk tree inspection in non-urban areas, the addition of digital data collection, fuel reduction partnerships, and safe tree programs. We also had a third-party study the effectiveness of this program and the preferred inspection cycle.

Situational awareness is designed to help us identify and respond to risk, including the fire risk maps, a fire weather dashboard, and installation of wildfire identification cameras and localized weather stations.

Operations and response measures are focused on automating our system to allow remote control and operation of key equipment including fire safety mode automation devices as well as fire safety mode and Public Safety Power Shutoff operations during critical fire weather, as well as expedited response agreements and other partnerships and relationships with external agencies such as first responders.

In 2025, we spent $36 million in capital and $15 million in operating expenses on wildfire resiliency efforts. In 2026, we expect to spend approximately $45 million in capital and $20 million in operating expenses related to the program. The IPUC and WUTC approved deferral and recovery of certain operating expenses of the wildfire resiliency plan, and we will continue to seek recovery of costs in future rate filings.

Wildfire Mitigation Legislation

In April 2025, Idaho enacted the Wildfire Standard of Care Act, which became effective in July 2025. This act requires public utilities in Idaho to prepare and submit to the IPUC for approval a wildfire mitigation plan on an annual basis. Once approved, the plan establishes the utility's duty to stakeholders to mitigate wildfire risk. In September 2025, the IPUC issued an order establishing a filing schedule. We filed our initial wildfire mitigation plan in December 2025. The plan focuses on grid hardening, vegetation management, situational awareness and operations and emergency response. The IPUC has up to six months to review and approve.

Also in April 2025, Washington enacted House Bill 1522, which became effective in July 2025. This bill requires electric utilities to file a wildfire mitigation plan with the WUTC, which must be approved or rejected within 60 days of submission. We, along with other stakeholders, are currently participating in the rulemaking process related to this legislation.

See "Note 22 of the Notes to Consolidated Financial Statements" for further discussion on wildfire activity and related litigation proceedings.

Natural Gas Operations

General

Avista Utilities provides natural gas distribution services to retail customers in parts of eastern Washington, northern Idaho, and northeastern and southwestern Oregon.

Market prices for natural gas, like other commodities, can be volatile. Our natural gas procurement strategy is to provide a reliable supply to our customers with some level of price certainty. We procure natural gas from various supply basins and over varying time periods. The resulting portfolio is a diversified mix of forward fixed price purchases, index and spot market purchases, and utilizing physical and financial derivative instruments. We also use natural gas storage to support high demand periods and the procurement of natural gas when prices may be lower. Securing prices throughout the year and even into subsequent years provides a level of price certainty and can mitigate price volatility to customers between years.

Weather is a key component of our natural gas customer load. This load is highly variable and daily natural gas loads can differ significantly from the monthly forecasted load projections. We make continuing projections of our natural gas loads and assess available natural gas resources. Based on these projections, we plan and execute a series of transactions to hedge a portion of our customers' projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend for multiple years. We also leave a portion of our natural gas supply requirements unhedged for purchase in the short-term spot markets.

As part of the process of balancing natural gas retail load requirements with resources, we engage in the wholesale purchase and sale of natural gas. We plan for sufficient natural gas delivery capacity to serve our retail customers for a theoretical peak day event. We generally have more pipeline and storage capacity than is needed during periods other than on a peak day. We optimize our natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Wholesale sales are delivered through wholesale market facilities outside of our natural gas distribution system. Natural gas resource optimization activities include, but are not limited to:

- wholesale market sales of surplus natural gas supplies,
- purchases and sales of natural gas to optimize use of pipeline and storage capacity, and
- participation in the transportation capacity release market.

We also provide distribution transportation service to qualified, large commercial and industrial natural gas customers who purchase natural gas through third-party marketers. For these customers, we receive their purchased natural gas from such third-party marketers into our distribution system and deliver it to the customers' premises. These customers generally pay the same rates as other customers in the same class, without charge for the cost of the natural gas delivered.

Optimization transactions that we engage in throughout the year are included in our annual purchased gas cost adjustment filings with the various commissions and are subject to review for prudence during this process.

Natural Gas Clean Energy Goals

We have an aspirational goal for our natural gas operations to be carbon neutral by 2045. Examples of carbon emissions reduction strategies include the following:

- diversify or transition from conventional fossil fuel natural gas to renewable natural gas, hydrogen, and other renewable biofuels,
- reduce natural gas consumption via conservation, energy efficiency and new technologies, and
- purchase carbon offsets as necessary.

See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion on clean energy, including applicable regulations.

We have several contracts for renewable natural gas to purchase an expected output of approximately 8.6 million therms annually from various projects.

Natural Gas Supply

We purchase natural gas, for both fuel for generation and delivery to natural gas customers, in wholesale markets and are connected to multiple supply basins in the western United States and Canada through firm capacity transportation rights on six different pipeline networks. Access to this diverse portfolio of natural gas resources allows for natural gas procurement decisions that benefit our natural gas customers. These interstate pipeline transportation rights provide the capacity to serve approximately 25 percent of peak natural gas customer demands from domestic sources and 75 percent from Canadian sources. Natural gas prices in the Pacific Northwest are affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada. Future prices and delivery constraints may cause our resource mix to vary.

Natural Gas Storage

Avista Utilities owns a one-third interest in Jackson Prairie, an underground aquifer natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 12 million therms, with a total working natural gas capacity of 256 million therms. Our share is one-third of the peak day deliverability and total working capacity. We also contract for additional storage capacity and delivery at Jackson Prairie from Northwest Pipeline for a portion of their one-third share of the storage project.

We optimize our natural gas storage capacity throughout the year by executing transactions that capture favorable market price spreads. Natural gas buyers identify opportunities to purchase lower cost natural gas in the immediate term to inject into storage, and then sell the gas in a forward market to be withdrawn later. The reverse of this type of transaction also occurs. These transactions lock in incremental value for customers. Jackson Prairie is also used as a variable peaking resource, and to protect from extreme daily price volatility during cold weather or other events affecting the market.

Future Gas Resource Needs

In March 2025, we filed our 2025 Natural Gas IRP with the WUTC, the IPUC and the OPUC. The IRP outlines a preferred resource portfolio which is designed to meet the forecast for system energy demand and comply with emissions legislation over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

Highlights of the 2025 Natural Gas IRP include the following expectations and/or assumptions:

- Customer usage estimates are increasingly difficult to forecast due to the variety of rules and codes passed by Oregon, Washington, and federal administrations. The Washington building codes are assumed to remain in effect. See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion of Washington building codes, including impacts to our business.
- The IRP focuses on greenhouse gas emissions compliance program constraints of the CCA in Washington and the CPP in Oregon.
- The Oregon preferred resource strategy assumes the utilization of renewable natural gas resources and energy efficiency investments, as well as emissions reductions after 2029 and carbon capture starting in 2035 as the primary tools to meet customer energy needs and comply with the CPP program requirements.
- The Washington preferred resource strategy assumes the utilization of conventional natural gas and energy efficiency, along with allowance offsets that are provided by the state or purchased by the Company and emissions reductions to meet the requirements under the CCA.

The state of Idaho currently does not have any greenhouse gas emissions reduction policies, and as such the preferred resource strategy continues to utilize natural gas from existing access to supply basins, and our existing storage.

See "Item 7. Management's Discussion and Analysis of Financial Condition—Environmental Issues and Contingencies" for further discussion of environmental laws, including impacts to our business.

We are required to file a natural gas IRP every two years and we anticipate our next IRP to be filed in 2027.

Utility Regulation

General

As a public utility, Avista Corp. is subject to regulation by state utility commissions for retail electric and natural gas rates, accounting, the issuance of securities and other matters. The retail electric and natural gas operations are subject to the jurisdiction of the WUTC, IPUC, OPUC and MPSC. Approval of the issuance of securities is not required from the MPSC. We are subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales.

Since Avista Corp. is a "holding company" (in addition to being itself an operating utility), we are subject to the jurisdiction of the FERC under the Public Utility Holding Company Act of 2005, which imposes certain reporting and record-keeping requirements on Avista Corp. and its subsidiaries. We and our subsidiaries are required to make books and records available to the FERC and the state utility commissions. In addition, upon the request of any jurisdictional state utility commission, the FERC would have the authority to review assignment of costs of non-power goods and administrative services among us and our subsidiaries. The FERC has the authority generally to require that rates subject to its jurisdiction be just and reasonable and, in this context, would continue to be able to, among other things, review transactions of an affiliated company.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a "cost of service" basis. Retail rates are designed to provide an opportunity to recover allowable operating expenses and earn a return of and a reasonable return on "rate base." Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred income taxes and other items and subject to possible reduction to the extent that a regulatory commission finds that part of an investment was imprudent. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and write-offs as authorized/ordered by the utility commissions. Our operating expenses and rate base are allocated or directly assigned to five regulatory jurisdictions: electric in Washington and Idaho, and natural gas in Washington, Idaho and Oregon. In general, requests for new retail rates are made based on revenues, operating expenses and net investment for a test year that ended prior to the date of the request, subject to possible adjustments, which differ among the various jurisdictions, designed to reflect the expected revenues, operating expenses and net investment during the period new retail rates will be in effect. The retail rates approved by the state commissions in a rate proceeding may not provide sufficient revenues to provide recovery of costs and a reasonable return on investment for a number of reasons, including, but not limited to, ongoing capital expenditures and unexpected changes in revenues and expenses following the time new retail rates are requested in the rate proceeding (known as "regulatory lag"), the denial by the commission of recovery, or timely recovery, of certain expenses or investment and the limitation by the commission of the authorized return on investment.

Our rates for wholesale electric sales and electric transmission services, as well as certain natural gas transportation services, are based on either "cost of service" principles or market-based rates as set forth by the FERC. See "Notes 1, 13 and 23 of the Notes to

Consolidated Financial Statements" for additional information about regulation (including power cost deferrals, purchased gas adjustments and decoupling mechanisms), depreciation and deferred income taxes.

See "Item 7. Management's Discussion and Analysis—Regulatory Matters" for information on general rate cases.

Federal Laws Related to Wholesale Competition

Federal law promotes practices that foster competition in the electric wholesale energy market. The FERC requires electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and requires electric utilities to enhance or construct transmission facilities to create additional transmission capacity for the purpose of providing these services. Public utilities (through subsidiaries or affiliates) and other entities may participate in the development of independent electric generating plants for sales to wholesale customers.

Public utilities operating under the FPA are required to provide open and non-discriminatory access to their transmission systems to third parties and establish an Open Access Same-Time Information System to provide an electronic means by which transmission customers can obtain information about available transmission capacity and purchase transmission access. The FERC also requires each public utility subject to the rules to operate its transmission and wholesale power merchant operating functions separately and to comply with standards of conduct designed to ensure that all wholesale users, including the public utility's power merchant operations, have equal access to the public utility's transmission system. Our compliance with these standards has not had a substantive impact on the operation, maintenance and marketing of our transmission system or our ability to provide service to customers.

See "Item 7. Management's Discussion and Analysis—Competition" for further information, as well as "Note 22 of the Notes to Consolidated Financial Statements" for discussion of a complaint filed with the FERC regarding transmission planning.

Regional Transmission Planning

Beginning with FERC Order No. 888 and continuing with subsequent rulemakings and policies, the FERC has encouraged better coordination and operational consistency aimed at capturing efficiencies that might otherwise be gained through the formation of a Regional Transmission Organization or an independent system operator.

We meet our FERC requirements to coordinate transmission planning activities with other regional entities through NorthernGrid. Launched in 2020, NorthernGrid is an association of all major transmission providers throughout the Pacific Northwest and Intermountain West, with facilities in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming. Through our participation in NorthernGrid, we meet the regional transmission planning requirements of FERC Order Nos. 890 and 1000, and follow-on orders. NorthernGrid and its members also work with other western organizations, including WestConnect and the California Independent System Operator (CAISO), to address broader interregional planning. Neither the costs nor requirements of participating in NorthernGrid's coordinated transmission planning activities are expected to materially impact our operations or financial performance.

Regional Energy Markets

The CAISO operates the Western Energy Imbalance Market (EIM) in the western United States. We are participants in the Western EIM, along with all investor-owned utilities in the Pacific Northwest. The Western EIM, among other things, facilitates regional load balancing by allowing certain generating plants to receive automated dispatch signals from the CAISO in five-minute intervals.

Reliability Standards

Among its other provisions, the U.S. Energy Policy Act provides for the implementation of mandatory reliability standards and authorizes the FERC to assess penalties for non-compliance with these standards and other FERC regulations.

The FERC certified the NERC as the single Electric Reliability Organization authorized to establish and enforce reliability standards and delegate authority to regional entities for the purpose of establishing and enforcing reliability standards, including but not limited to cybersecurity measures. The FERC approves NERC Reliability Standards, including western region standards that make up the set of legally enforceable standards for the United States bulk electric system. We are required to self-certify our compliance with these standards on an annual basis and undergo regularly scheduled periodic reviews by the NERC and its regional entity, the Western Electricity Coordinating Council (WECC). Failure to comply with NERC reliability standards could result in substantial financial penalties. We have a robust internal compliance program in place to manage compliance activities and mitigate the risk of potential noncompliance with these standards. We do not expect the costs associated with compliance with these standards to have a material impact on our financial results.

As both a balancing authority and transmission operator, we must operate under the oversight of a reliability coordinator per NERC reliability standards. RC West is the reliability coordinator of record for 41 balancing authorities and transmission operators in the Western Interconnection, including Avista Corp. RC West oversees grid compliance with federal and regional grid standards, and can determine measures to prevent or mitigate system emergencies in day-ahead or real-time operations.

Vulnerability to Cyberattack

The energy sector, including electric and natural gas utility companies, has become the subject of cyberattacks with increased frequency and we, along with other utility companies, are the target of these frequent attacks.

A successful attack on our administrative networks could compromise the security and privacy of data, including operating, financial and personal information. A successful attack on our operating networks could impair the operation of our electric and/or natural gas utility facilities, possibly resulting in our inability to provide electric and/or natural gas service for extended periods of time.

We continually reinforce and update our defensive systems and comply with the NERC's reliability standards. See "Reliability Standards," "Item 1A. Risk Factors—Cybersecurity Risk Factors" and "Item 1C. Cybersecurity" for further information.

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

Years Ended December 31,

	2025	2024	2023
Electric Operations			
Operating Revenues (Dollars in Millions):			
Residential	$ 550	$ 473	$ 425
Commercial	402	369	344
Industrial	142	131	110
Public street and highway lighting	9	9	8
Total retail	1,103	982	887
Wholesale	187	225	250
Sales of fuel	20	13	(26)
Other	34	81	61
Total electric operating revenues	$ 1,344	$ 1,301	$ 1,172
Energy Sales (Thousands of MWhs):			
Residential	4,114	4,018	4,020
Commercial	3,216	3,166	3,160
Industrial	1,912	1,785	1,671
Public street and highway lighting	15	17	17
Total retail	9,257	8,986	8,868
Wholesale	4,457	3,740	3,468
Total electric energy sales	13,714	12,726	12,336
Energy Resources (Thousands of MWhs):			
Hydroelectric generation (from Company facilities)	3,195	3,168	3,024
Thermal generation (from Company facilities)	4,815	4,995	5,084
Purchased power	6,040	4,965	5,121
Power exchanges	(13)	(14)	(421)
Total power resources	14,037	13,114	12,808
Energy losses and Company use	(323)	(388)	(472)
Total energy resources (net of losses)	13,714	12,726	12,336
Number Of Retail Customers (Average for Period):			
Residential	376,349	371,076	366,450
Commercial	45,959	45,794	45,341
Industrial	1,159	1,175	1,188
Public street and highway lighting	761	739	690
Total electric retail customers	424,228	418,784	413,669
Residential Service Averages:			
Annual use per customer (kWh)	10,931	10,827	10,971
Revenue per kWh (in cents)	13.37	11.78	10.58
Annual revenue per customer (in dollars)	$ 1,462	$ 1,276	$ 1,160
Average Hourly Load (aMW)	1,149	1,117	1,115

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

Years Ended December 31,

	2025	2024	2023
Electric Operations (continued)			
Retail Native Load at time of system peak (MW):			
Winter	1,832	1,869	1,771
Summer	1,837	1,831	1,809
Cooling Degree Days: (1)			
Spokane, WA			
Actual	845	903	811
Historical average	607	596	585
% of average	139%	152%	139%
Heating Degree Days: (2)			
Spokane, WA			
Actual	5,782	5,875	6,012
Historical average	6,521	6,569	6,557
% of average	89%	89%	92%

(1) Cooling degree days are the measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day is above 65 degrees Fahrenheit (annual degree days above historical average indicate warmer than average temperatures).

(2) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day is below 65 degrees Fahrenheit (annual degree days below historical averages indicate warmer than average temperatures).

AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS

Years Ended December 31,

		2025		2024		2023
Natural Gas Operations						
Operating Revenues (Dollars in Millions):						
Residential	$	291	$	317	$	326
Commercial		137		163		164
Interruptible		9		9		13
Industrial		3		4		4
Total retail		440		493		507
Wholesale		52		61		55
Transportation		13		11		8
Other		79		41		1
Total natural gas operating revenues	$	584	$	606	$	571
Therms Delivered (Thousands of Therms):						
Residential		209,200		217,808		225,665
Commercial		132,932		137,972		138,719
Interruptible		25,503		20,682		20,158
Industrial		4,732		4,347		4,914
Total retail		372,367		380,809		389,456
Wholesale		228,646		271,803		262,188
Transportation		156,883		178,236		165,066
Interdepartmental and Company use		389		391		413
Total therms delivered		758,285		831,239		817,123
Number Of Retail Customers (Average for Period):						
Residential		346,048		343,267		340,655
Commercial		37,481		37,353		37,193
Interruptible		51		52		50
Industrial		184		185		187
Total natural gas retail customers		383,764		380,857		378,085
Residential Service Averages:						
Annual use per customer (therms)		605		635		662
Revenue per therm (in dollars)	$	1.39	$	1.46	$	1.44
Annual revenue per customer (in dollars)	$	840	$	925	$	956
Heating Degree Days: (1)						
Spokane, WA						
Actual		5,782		5,875		6,012
Historical average		6,521		6,569		6,557
% of average		89%		89%		92%
Medford, OR						
Actual		4,169		3,963		4,295
Historical average		4,252		4,282		4,248
% of average		98%		93%		101%

(1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day is below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures).

AEL&P is the primary operating subsidiary of AERC, and the sole utility providing electrical energy in Juneau, Alaska. Juneau is a geographically isolated community with no electric interconnections with the transmission facilities of other utilities and no pipeline access to natural gas or other fuels. Juneau's economy is primarily driven by government activities, tourism, commercial fishing, and mining, as well as activities as the commercial hub of southeast Alaska.

AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity. AEL&P owns four of these generation facilities (totaling 24.5 MW of capacity) and has a PPA for the output of the Snettisham Hydroelectric Project (totaling 78.2 MW of capacity).

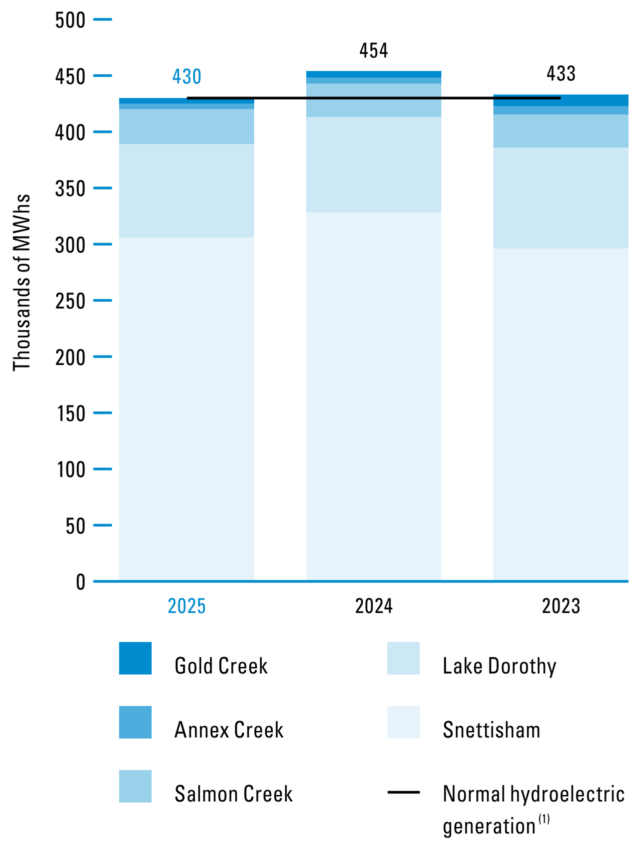
The Snettisham Hydroelectric Project is owned by the Alaska Industrial Development and Export Authority (AIDEA), a public corporation of the State of Alaska. AIDEA issued revenue bonds in 1998 (which were refinanced in 2015) to finance its acquisition of the project. These bonds were outstanding in the amount of $36 million as of December 31, 2025 and mature in January 2034. AEL&P has a PPA and operating and maintenance agreement with the AIDEA to operate and maintain the facility. This PPA is a take-or-pay obligation, expiring in December 2038. AIDEA's bonds are payable solely out of the revenues received under the PPA. Amounts payable by AEL&P under the PPA are equal to the required debt service on the bonds plus operating and maintenance costs.

This PPA is a finance lease and, as of December 31, 2025, the finance lease obligation was $36 million. Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project at any time for a price equal to the principal amount of the bonds outstanding at that time. See "Note 5 of the Notes to Consolidated Financial Statements" for further discussion of the Snettisham finance lease obligation.

AEL&P has 107.5 MW of diesel generating capacity from four facilities to provide back-up service to firm customers when necessary.

The following graph shows AEL&P's hydroelectric generation (in thousands of MWhs) during the time periods indicated below:

HYDROELECTRIC GENERATION



(1) Normal hydroelectric generation is defined as the energy output of the plant during a year with average inflows to the reservoir.

As of December 31, 2025, AEL&P served approximately 17,600 customers. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AEL&P's customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AEL&P maintains separate rate tariffs for each of its customer classes, as well as seasonal rates.

AEL&P's operations are subject to regulation by the RCA with respect to customer rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities.

AEL&P is subject to the jurisdiction of the FERC with respect to permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Lake Dorothy hydroelectric project) expires in 2053 while the other (for the Salmon Creek and Annex Creek hydroelectric projects) expires in 2058. Gold Creek is not subject to a FERC license requirement. Since AEL&P has no electric interconnection with other utilities and makes no wholesale sales, it is not subject to general FERC jurisdiction, other than the reporting and other requirements of the Public Utility Holding Company Act of 2005 as an Avista Corp. subsidiary.

The Snettisham Hydroelectric Project is subject to regulation by the State of Alaska with respect to dam safety and certain aspects of its operations. AEL&P is subject to regulation with respect to air and water quality, land use and other environmental matters under both federal and state laws.

AEL&P ELECTRIC OPERATING STATISTICS

Years Ended December 31,

	2025	2024	2023
Electric Operations			
Operating Revenues (Dollars in Millions):			
Residential	$ 22	$ 22	$ 20
Commercial and government	25	27	27
Total retail	47	49	47
Other	—	1	1
Total electric operating revenues	$ 47	$ 50	$ 48
Energy Sales (Thousands of MWhs):			
Residential	169	171	161
Commercial and government	232	255	249
Public street and highway lighting	1	1	1
Total electric energy sales	402	427	411
Number Of Retail Customers (Average for Period):			
Residential	15,330	15,236	15,142
Commercial and government	2,389	2,338	2,327
Public street and highway lighting	251	249	248
Total electric retail customers	17,970	17,823	17,717
Residential Service Averages:			
Annual use per customer (kWh)	11,045	11,192	10,633
Revenue per kWh (in cents)	12.66	12.66	12.54
Annual revenue per customer (in dollars)	$ 1,398	$ 1,417	$ 1,336
Heating Degree Days: (1)			
Juneau, AK			
Actual	8,118	8,139	7,550
Historical average	8,336	8,336	8,336
% of average	97%	98%	91%

(1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day is below 65 degrees Fahrenheit (annual heating degree days below historical average indicate warmer than average temperatures).

OTHER BUSINESSES

The following table shows our assets related to our other businesses, including intercompany amounts as of December 31 (dollars in millions):

Entity and Asset Type	2025	2024
Avista Capital		
Equity investments	$ 148	$ 157
Notes receivable—third parties	11	18
Other assets	6	7
Alaska companies (AERC and AJT Mining)	12	12
Total	$ 177	$ 194

Avista Capital's equity investments are primarily investments in emerging technology and biotechnology companies and venture capital funds, as well as investment in a joint venture focused on local real estate development and economic growth.

Alaska companies includes AERC and AJT Mining, which is a wholly owned subsidiary of AERC and is an inactive mining company holding certain real estate.

ITEM 1A. RISK FACTORS

RISK FACTORS

The following factors could have a significant impact on our operations, results of operations, financial condition or cash flows. These factors could cause future results or outcomes to differ materially from those discussed in our reports filed with the SEC (including this Annual Report on Form 10-K), and elsewhere. See "Forward-Looking Statements" for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements. Additional risks and uncertainties not presently known to us or that we currently do not consider material could also adversely affect us. The realization of many of the risks discussed herein depends upon the prior occurrence of some event or circumstance—i.e., a "trigger". We may or may not discuss the occurrence of a trigger that has not resulted in an adverse effect on us, and the absence of such disclosure should not be construed as a representation that no such trigger has occurred.

Utility Regulatory Risk Factors

Regulators may not grant rates that provide timely or sufficient recovery of our costs or allow a reasonable rate of return for our shareholders.

Avista Utilities' annual operating expenses and the costs associated with incremental investments in utility assets continue to grow at a faster rate than revenue. Our ability to recover these expenses and capital costs depends on the adequacy and timeliness of retail rate increases allowed by regulatory agencies, as well as managing costs. We expect to periodically file for rate increases with regulatory agencies to recover our expenses and capital costs and provide an opportunity to earn a reasonable rate of return for shareholders. If regulators do not grant rate increases or grant substantially lower rate increases than our requests in the future or if recovery of deferred expenses is disallowed, or if regulators do not allow us to recover costs associated with assets required to be retired or divested to comply with emerging laws and regulations, it could have a negative effect on our financial condition, results of operations or cash flows. See further discussion of regulatory matters in "Item 7. Management's Discussion and Analysis—Regulatory Matters."

In the future, we may no longer meet the criteria for continued application of regulatory accounting principles for all or a portion of our regulated operations.

If we could no longer apply regulatory accounting principles, we could be:

- required to write off our regulatory assets, and be
- precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if we expect to recover these amounts from customers in the future.

See further discussion at "Note 1 of the Notes to Consolidated Financial Statements—Regulatory Deferred Charges and Credits."

Operational Risk Factors

Wildfires ignited, or allegedly ignited, by Avista Corp. equipment or facilities, could cause significant loss of life and property, thereby causing serious operational and financial harm.

Our equipment may be the ignition source, or alleged cause of ignition, for wildfires and in the event of a fire caused by our equipment, we could potentially be held liable for resulting damages to life and property, as well as fire suppression costs. Also, wildfires could lead to extended operational outages of our equipment while we wait for the wildfire to be extinguished before restoring power, and the cost to implement rapid response or repair to such facilities could be significant. Wildfires caused by our equipment could cause significant damage to our reputation, which could erode shareholder, customer and community satisfaction. In addition, wildfires caused by our equipment could lead to increased litigation and insurance costs, loss of insurance coverage, the need to be self-insured or the need to consider non-traditional insurance coverage or other risk mitigation procedures. Wildfire risks may be exacerbated by increasing temperatures and/or decreasing precipitation due to climate change.

We are subject to various operational and event risks.

Our operations are subject to operational and event risks that include:

- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, floods, snow and ice storms, and heat waves due to normal weather variations as well as the impacts of climate change which could disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies, support services and general business operations,
- blackouts or disruptions of interconnected transmission systems (the regional power grid),
- unplanned outages at generating plants,
- changes in the availability and cost of purchased power, fuel and natural gas, including delivery constraints and restrictions imposed by the transition to renewable and/or non-emitting energy sources, which can disrupt service to customers,

- explosions, fires, accidents, or mechanical breakdowns that could occur while operating and maintaining our generation, transmission and distribution systems, including, but not limited to, increased risk associated with emerging renewable technologies as these technologies continue to mature,
- property damage or injuries to third parties caused by our generation, transmission and distribution systems,
- dam failure at a company-owned hydroelectric facility,
- natural disasters that can disrupt energy generation, transmission and distribution, and general business operations,
- terrorist attacks or other malicious acts that may disrupt or cause damage to our utility assets or the vendors we utilize,
- increased costs or delay of capital projects associated with the ability of suppliers, vendors or contractors to perform, and
- general workforce problems, including decreased employee engagement, which may impact strategy execution and negatively affect retention, ability to attract workers, and result in challenges in collective bargaining, possible work stoppages, and strikes. Retention of employees may also be negatively impacted by early retirements, insufficient remote work opportunities, and higher pay offered by other employers. Attractions of employees to support strategies may be affected by higher pay offered from other companies, more liberal remote work opportunities offered by other employers, and other work-life balance benefits afforded by other companies.

Disasters could affect the general economy, financial and capital markets, specific industries or our ability to conduct business. As protection against operational and event risks, we maintain business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and we seek to negotiate indemnification arrangements with contractors for certain event risks. However, insurance or indemnification agreements may not be adequate to protect against liability, extra expenses and operating disruptions from the operational and event risks described above. In addition, we are subject to the risk that insurers and/or other parties will dispute or be unable to perform on their obligations. If insurance or indemnification agreements are unable to adequately protect us or reimburse us for out-of-pocket costs, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Damage to facilities could be caused by severe weather or natural disasters, such as snow, ice, wind storms, floods, wildfires, earthquakes or avalanches. The cost of implementing rapid response or repair to such facilities can be significant. Overhead electric lines are most susceptible to damage caused by severe weather and are not covered by insurance.

Physical attacks on our assets could have a negative impact on our business and our results of operations.

Our generation, transmission and distribution assets and the systems that monitor and operate these assets are critical infrastructure for providing service to our customers. Security threats are continuing to evolve, and our industry is subject to attempts to disrupt operations. Significant destruction or interruption of these assets and systems could prevent us from fulfilling our critical business functions, including delivering energy to customers. This could result in experiencing a loss of revenues and/or additional costs to replace or restore assets and systems, and may increase costs associated with heightened security requirements.

Lack of control over facilities under PPAs could impact power supply costs.

Generating facilities not owned by us, whose output we acquire under a PPA, could be foreclosed on by creditors of the owner, even though we are performing under the terms of the PPA. This could result in either an increase in the price to be paid by us, or the output of the facilities being diverted from us and sold to other parties.

Adverse impacts to AEL&P could result from an extended outage of its hydroelectric generating resources or its inability to deliver energy, due to its lack of interconnectivity to other electrical grids and the cost of replacement power (diesel).

AEL&P operates several hydroelectric power generation facilities and has diesel generating capacity to provide backup service to firm customers when necessary; however, a single hydroelectric power generation facility, the Snettisham Hydroelectric Project, provides approximately two-thirds of AEL&P's hydroelectric power generation. Issues that negatively affect AEL&P's ability to generate or transmit power or a decrease in the demand for the power generated by AEL&P could negatively affect our results of operations, financial condition and cash flows.

Climate Change Risk Factors

A trend of increasing average temperatures and its effects could cause significant direct and indirect impacts on our operations and results of operations.

Climate change may exacerbate existing risks related to weather and weather-related events. Potential direct effects of climate change include changes in the timing and magnitude of snowpack and streamflow, impacting hydroelectric generation; timing and magnitude of changes in electric and gas load; increased weather-related stress on, or damage to, energy infrastructure; increased frequency and intensity of extreme weather events that may impact energy generation and delivery.

Indirect impacts associated with climate change may include increased costs to generate electricity or secure natural gas and deliver energy to customers; impacts to the timing or amount of operating revenues; increased costs to maintain or construct energy infrastructure in adaptation to a changing climate; increased costs or inability to obtain insurance coverage; and regional impacts to the demographic makeup, economy or financial conditions of our customers. Indirect impacts also include risks associated with new and emerging laws and regulations, which could have a material adverse impact on our business and results of operations. See further discussion at "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies."

Cybersecurity Risk Factors

Cyberattacks, ransomware, terrorism or other malicious acts could disrupt our businesses and have a negative impact on our results of operations and cash flows.

We rely on interconnected technology systems for operation of our generating plants, electric transmission and distribution systems, natural gas distribution systems, customer billing and customer service, accounting and other administrative processes and compliance with various regulations. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees.

Cyberattacks, ransomware, terrorism or other malicious acts could damage, destroy or disrupt these systems for an extended period of time. The energy sector, including electric and natural gas utility companies have become the subject of cyberattacks with increased frequency. Our administrative and operating networks are targeted by hackers on a regular basis. Additionally, the facilities and systems of clients, suppliers and third party service providers could be vulnerable to the same cyber or terrorism risks as our facilities and systems and such third party systems may be interconnected to our systems both physically and technologically. Therefore, an event caused by cyberattacks, ransomware or other malicious act at an interconnected third party could impact our business and facilities similarly. Any failure, unexpected, or unauthorized use of technology systems could result in the unavailability of such systems, and could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. Any of the above could also result in the loss or release of confidential customer and/or employee information or other proprietary data that could adversely affect our reputation and competitiveness, could result in costly litigation and negatively impact our results of operations. These cyberattacks have become more common and sophisticated and, as such, we could be required to incur costs to strengthen our systems and respond to emerging concerns.

There are various risks associated with technology systems such as hardware or software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other deliberate or inadvertent human errors.

Technology Risk Factors

Our technology may become obsolete, development of new technologies could create additional risk, or we may not have sufficient resources to manage our technology.

Our technology may become obsolete before the end of its useful life. In addition, custom or new technology (including generative artificial intelligence) that is heavily relied upon may not be maintained and updated appropriately due to resource restraints, or other factors, which could cause technology failures or give rise to additional operational or security risks. Generative artificial intelligence could also create additional regulatory scrutiny and generate uncertainty around intellectual property ownership and/or licensing or use. Technology (including artificial intelligence) is also subject to intentional misuse (by criminals, terrorists or other bad actors). Technology failures or incidents of misuse could result in significant adverse effects on our operations, results of operations, financial condition and cash flows.

We may be adversely affected by our inability to successfully implement certain technology projects.

There are inherent risks associated with replacing and changing systems, which could have a material adverse effect on our results of operations, financial condition and cash flows. Finally, there is the risk that we ultimately do not complete a project and will incur contract cancellation or other costs, which could be significant.

Problems with the transition, design or implementation of our new enterprise resource planning system could interfere with our business and operations, and adversely affect our financial condition.

We are in the process of planning for the implementation of a new cloud-based enterprise resource planning system, which will take multiple years to complete. See further information on the enterprise resource planning system within "Item 7. Management's Discussion and Analysis—Executive Overview". There are transitional risks associated with the implementation, which may include loss of data in the conversion from on-premises systems to the cloud, difficulty compiling data for external reporting requirements, costs increasing throughout the project, or other challenges in our business operations. Difficulties faced during the transition could have a material adverse effect on our business, financial condition, and results of operations.

The expanded adoption of artificial intelligence has the potential to increase exposure to cyberattacks and negatively impact business operations.

The adoption of artificial intelligence (AI) is driving demand for energy while also presenting opportunities and unique risks to the utility business. AI enabled tools are proving to increase efficiency and add value to daily work processes as the use and adoption continues to expand. While use cases to drive efficiencies through AI develop, cyber attackers are targeting the tools and systems used to create the efficiencies, requiring enhanced analytics and monitoring. Reliance on AI generated information and data may enhance the exposure risk over time.

AI driven solutions will be essential to compete in the marketplace. Whether it be for material or energy procurement, or financial transactions, AI will accelerate data driven decision making. Therefore, AI literacy is essential. Not advancing the understanding and use of AI may compromise the operational and financial progress of the Company.

Strategic Risk Factors

Our strategic business plans, which may be affected by the foregoing, may change, including the entry into new businesses and/or the exit from existing businesses and/or the curtailment of our business development efforts where potential future business is uncertain.

Our strategic business plans could be affected by or result in the following:

- disruptive innovations in the marketplace may outpace our ability to compete or manage our risk (including the transition to renewable and/or non-emitting energy resources),
- customers may have a choice in the future over the sources from which to receive their energy, and we may not be able to compete,
- potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management

resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities,
- reduced control over generation resources resulting from reliance on contract power from third-party owners of generation assets, which could limit our ability to balance resources with demand,
- market or other conditions that could adversely affect our operations or require changes to our business strategy and could result in reduced assets and net income,
- affordability of electric and/or gas services may be a challenge for customers resulting in increased delayed payment for utility services,
- potential reputational risk arising from repeated general rate case filings, degradation in the quality of service, or from failed strategic investments and opportunities, which could erode shareholder, customer and community satisfaction with the Company, and
- the risk of municipalization or other form of service territory reduction.

Non-regulated investments in businesses outside of our core utilities operations may increase earnings volatility and can be difficult to sell due to their illiquid nature.

The fair values of our respective equity investments fluctuate from period to period, and such changes in fair value directly affect our net income. While we make these investments after prudent analysis and with the expectation of eventual financial gains, there is no assurance these investments will ultimately be successful. A significant portion of our investment portfolio consists of equity interests in privately held companies, which are inherently illiquid due to a lack of established market. Liquidity events are largely outside of our control, and may not occur on a timely basis (or may never occur). In addition, it is likely the value of these investments will continue to fluctuate as the businesses continue to mature, causing corresponding changes in our net income. The risks faced by these businesses may differ from the risks faced by our utility operations.

External Mandates Risk Factors

External mandate risk involves forces outside the Company, which may include significant changes in customer expectations, disruptive technologies that result in obsolescence of our business model and government action that could impact the Company.

Actions or limitations to address concerns over long-term climate change, both globally and within our utilities' service areas, may affect our operations and financial performance.

Legislative, regulatory and advocacy efforts at the local, state, national and international levels concerning climate change and other environmental issues could have significant impacts on our operations. The electric and natural gas utility industries are frequently affected by proposals to curb greenhouse gas and other air emissions. Various regulatory and legislative proposals have been made to limit or further restrict byproducts of combustion, including those resulting from the use of natural gas by our customers. In addition, there are regulatory and legislative initiatives that have been passed which are designed to limit greenhouse gas emissions and increase the use of renewable sources of energy. In addition, regulatory and legislative initiatives may restrict customers' access to natural gas and/or require or limit natural gas infrastructure in buildings. Other initiatives may seek to promote social interests expressed as energy equity, environmental justice or similar frameworks. Such legislation could direct and/or restrict the operation and raise the costs of our power generation resources and energy delivery infrastructure as well as the distribution of natural gas to our customers.

We expect continuing legislative and regulatory activity in the future, and we are evaluating the extent to which potential changes to environmental laws and regulations may:

- increase the operating costs of generating plants,
- increase the lead time and capital costs for the construction of new generating plants,
- require modification of our existing generating plants,
- require existing generating plant operations to be curtailed or shut down,
- reduce the amount of energy available from our generating plants,
- restrict the types of generating plants that can be built or contracted with,
- require construction of specific types of generation plants at higher cost, including emerging generation sources still in development that operate at a higher risk of failure, and
- increase the cost or limit our ability to distribute natural gas to customers.

See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" for discussion regarding environmental issues and legislation which may affect our operations.

We have contingent liabilities, including certain matters related to potential environmental liabilities, and cannot predict the outcome of these matters.

In the normal course of our business, we have matters that are the subject of ongoing litigation, mediation, investigation and/or negotiation. We cannot predict the ultimate outcome or potential impact of any issue, including the extent, if any, of insurance coverage or recovery through the ratemaking process. We are subject to environmental regulation by federal, state and local authorities related to our past, present and future operations. See "Note 22 of the Notes to Consolidated Financial Statements" for further details of these matters.

Import tariffs could lead to increased prices on energy commodities and/or equipment and materials that are critical to our business.

Tariffs and other restrictions on trade with foreign countries could significantly increase the prices of energy commodities (electricity and natural gas) and equipment and materials that are critical to our business. In addition, tariffs and trade restrictions could have a similar impact on our suppliers and certain customers, which could have a negative impact on our financial condition, results of operations and cash flows.

See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" and "Forward-Looking Statements" for discussion of or reference to additional external mandates which could have a material adverse effect on our results of operations, financial condition and cash flows.

Financial Risk Factors

Weather (temperatures, precipitation levels, wind patterns and storms) has a significant effect on our results of operations, financial condition and cash flows. These effects could increase as climate changes occur.

Weather impacts are described in the following subtopics:

- certain retail electricity and natural gas sales,
- the cost of natural gas supply, and
- the cost of power supply.

Certain retail electricity and natural gas sales volumes vary directly with changes in temperatures. We normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce our customers' energy demand and our retail operating revenues. The revenue and earnings impact of weather fluctuations is somewhat mitigated by our decoupling mechanisms; however, we could experience liquidity constraints during the period between when decoupling revenue is earned and when it is subsequently collected from customers through retail rates.

The cost of natural gas supply is impacted by both supply-side factors (amount of natural gas production, level of natural gas in storage, volumes of natural gas imports and exports, regulatory restraints or costs on natural gas production and delivery) and demand-side factors (variations in weather, level of economic growth, availability and prices of other fuels). Prices tend to increase with higher demand during periods of cold weather. Inter-regional natural gas pipelines and competition for supply can allow demand-driven price volatility in other regions of North America to affect prices in the Pacific Northwest. Increased costs adversely affect cash flows when we purchase natural gas for retail supply at prices above the amount allowed for recovery in retail rates. We defer differences between actual natural gas supply costs and the amount currently recovered in retail rates and we are generally allowed to recover substantially all of these differences after regulatory review. However, these deferred costs require cash outflows from the time of natural gas purchases until the costs are later recovered through retail rates.

The cost of power supply can be significantly affected by weather, and therefore is subject to trends in climate change. Precipitation (consisting of snowpack, its water content and runoff pattern plus rainfall) and other streamflow conditions (such as regional water storage operations) significantly affect hydroelectric generation capability. Variations in hydroelectric generation inversely affect our reliance on market purchases and thermal generation. To the extent that hydroelectric generation is less than normal, more costly power supply resources must be dispatched or acquired and the ability to realize net benefits from surplus hydroelectric wholesale sales is reduced. Wholesale prices also vary based on wind patterns as wind generation capacity is material in the Pacific Northwest but its contribution to supply is inconsistent.

The price of power in the wholesale energy markets tends to be higher during periods of high regional demand, such as occurs with temperature extremes. Climate change may increase the frequency and magnitude of temperature extremes. We may need to purchase power in the wholesale market during peak price periods. The price of natural gas as fuel for natural gas-fired electric generation tends to increase during periods of high demand which are often related to temperature extremes. We may need to purchase natural gas fuel in these periods of high prices to meet electric demands. The cost of power supply during peak usage periods may be higher than the retail sales price or the amount allowed in retail rates by our regulators. To the extent that power supply costs are above the amount allowed currently in retail rates, the difference is partially absorbed by the Company in current expense and is partially deferred or shared with customers through regulatory mechanisms. However, these deferred costs require cash outflows from the time of power purchases until the costs are later recovered through retail rates.

The price of power tends to be lower during periods with excess supply, such as the spring when hydroelectric conditions are usually at their maximum and various facilities are required to operate to meet environmental mandates. Oversupply can be exacerbated when intermittent resources such as wind generation produce output that may be supported by price subsidies. In extreme situations, we may be required to sell excess energy at negative prices.

As a result of these combined factors, our net cost of power supply—the difference between our costs of generation and market purchases, reduced by our revenue from wholesale sales—varies significantly because of weather.

We rely on regular access to financial markets, but we cannot assure favorable or reasonable financing terms will be available when we need them.

Access to capital markets is critical to our operations and our capital structure. We have significant capital requirements that we expect to fund, in part, by accessing capital markets. As such, the state of financial markets and credit availability in the global, United States and regional economies impact our financial condition. We could experience increased borrowing costs or limited access to capital on reasonable terms.

We access long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital, including needs related to power and natural gas purchases and sales, from time-to-time. Our ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or prohibit our ability to finance capital expenditures and repay maturing long-term debt. Our liquidity needs could exceed our short-term credit availability and lead to defaults on various financing arrangements. We would also likely be prohibited from paying dividends on our common stock.

Performance of the financial markets could also result in significant declines in the market values of assets held by our pension plan and/or a significant increase in the pension liability (which impacts the funded status of the plan) and could increase future funding obligations and pension expense.

We rely on credit from financial institutions for short-term borrowings. We need adequate levels of credit with financial institutions for short-term liquidity. There is no assurance that we will have access to credit beyond the expiration dates of our committed line of credit agreements. These agreements contain customary covenants and default provisions.

Any default on the lines of credit or other financing arrangements of Avista Corp. or our "significant subsidiaries," if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock.

Downgrades in our credit ratings could impede our ability to obtain financing, adversely affect the terms of financing and impact our ability to transact for or hedge energy resources. If we do not maintain our investment grade credit rating with the major credit rating agencies, we could expect increased debt service costs, limitations on our ability to access capital markets or obtain other financing on reasonable terms, and requirements to provide collateral (in the form of cash or letters of credit) to lenders and counterparties. In addition, credit rating downgrades could reduce the number of counterparties willing to do business with us or result in the termination of outstanding regulatory authorizations for certain financing activities.

Credit risk may be affected by industry concentration and geographic concentration.

We have concentrations of suppliers and customers in the electric and natural gas industries, including:

- electric and natural gas utilities,
- electric generators and transmission providers,
- oil and natural gas producers and pipelines,
- financial institutions including commodity clearing exchanges and related parties, and
- energy marketing and trading companies.

We have concentrations of credit risk related to our geographic location in the western United States and western Canada energy markets. These concentrations of counterparties and concentrations of geographic location may affect our overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

We are a participant in the EIM, and engage in direct and indirect power purchase and sale transactions in connection with that participation. The EIM collateral requirements are based on established credit criteria, but there is no assurance the collateral will be sufficient to cover obligations that counterparties may owe each other in the EIM, and credit losses could be allocated among all EIM participants, including us. A significant failure of a participant in the EIM to make payments when its obligations are due could have a ripple effect on our counterparties in the power and gas markets if those counterparties experience ancillary liquidity issues, and could result in a decline in the ability of our counterparties to perform on their obligations.

Activist shareholder actions could have a negative impact on our business and operations.

Shareholder activism can take many forms and arise in a variety of situations. Actions by activist shareholders could include engaging in proxy solicitations, making or advancing shareholder proposals, or otherwise attempting to assert influence on our board of directors and/or management. Response to these actions could result in substantial costs, require significant attention from our board of directors and management, and divert resources from the execution of our strategy and business operations.

Shareholder activism could result in perceived uncertainties, negatively affect our business opportunities, our ability to access capital markets, and relationships with our customers and employees. These actions could have a material adverse effect on our financial condition and results of operations, and could result in significant fluctuations in the trading price of our common stock based on market perceptions or other factors.

Energy Commodity Risk Factors

Energy commodity price changes affect our cash flows and results of operations.

Energy commodity prices can be volatile. We rely on energy markets and other counterparties for energy supply, surplus and optimization transactions and commodity price hedging. A combination of factors exposes our operations to commodity price risks, including:

- our obligation to serve our retail customers at rates set through the regulatory process—we cannot decline to serve our customers and we cannot change retail rates to reflect current energy prices unless and until we receive regulatory approval,
- customer demand, which is beyond our control because of weather, customer choices, prevailing economic conditions and other factors,
- some of our energy supply cost is fixed by the nature of the energy-producing assets or through contractual arrangements (however, a significant portion of our energy resource costs are not fixed), and
- the potential non-performance by commodity counterparties, which could lead to replacement of the scheduled energy or natural gas at higher prices.

Because we must supply the amount of energy demanded by our customers and we must sell it at fixed rates and only a portion of our energy supply costs are fixed, we are subject to the risk of buying energy at higher prices in wholesale energy markets (and the risk of selling energy at lower prices if we are in a surplus position). Electricity and natural gas in wholesale markets are commodities with historically high price volatility. Changes in wholesale energy prices affect, among other things, the cash requirements to purchase electricity and natural gas for retail customers or wholesale obligations and the market value of derivative assets and liabilities.

We hedge a portion of our energy commodity risk with physical and financial derivative instruments that may require the posting of collateral. When we enter into fixed price energy commodity transactions for future delivery, we are subject to credit terms that may require us to provide collateral to wholesale counterparties related to the difference between forward prices and the agreed upon fixed prices. These collateral requirements can place significant demands on our cash flows or borrowing arrangements. Price volatility can cause collateral requirements to change quickly and significantly.

Cash flow deferrals related to energy commodities can be significant. We are permitted to collect from customers only amounts approved by regulatory commissions. However, our costs to provide energy service can be much higher or lower than the amounts currently billed to customers. We are permitted to defer income statement recognition and recovery from customers for some of these differences, which are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators, who have discretion as to the extent and timing of future recovery or refund to customers.

Power and natural gas costs higher than those recovered in retail rates negatively impact cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect our results of operations.

Even if our regulators ultimately allow the recovery of deferred power and natural gas costs, our operating cash flows can be negatively affected until these costs are recovered from customers.

Fluctuating energy commodity prices and volumes in relation to our energy risk management process can cause volatility in our cash flows and results of operations. We engage in active hedging and resource optimization practices to reduce energy cost volatility and economic exposure related to commodity price fluctuations. We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity and natural gas, as well as forecasted excess or deficit energy positions and inventories of natural gas. We use physical energy contracts and derivative instruments, such as forwards, futures, swaps and options traded in the over-the-counter markets or on exchanges. If market prices decrease compared to the prices we have locked in with our energy commodity derivatives, this will result in a liability related to these derivatives, which can be significant. As a result of price fluctuations, we may be required to post significant amounts of cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments.

We do not attempt to fully hedge our energy resource assets or our forecasted net positions for various time horizons. To the extent we have positions that are not hedged, or if hedging positions do not fully match the corresponding purchase or sale, fluctuating commodity prices could have a material effect on our operating revenues, resource costs, derivative assets and liabilities, and operating cash flows. In addition, actual loads and resources typically vary from forecasts, sometimes to a significant degree, which require additional transactions or dispatch decisions that impact cash flows.

The hedges we enter into are reviewed for prudence by our various regulators and deferred costs (including those as a result of our hedging transactions) are subject to review for prudence and potential disallowance by regulators.

Generation plants may become obsolete. We rely on a variety of generation and energy commodity market sources to fulfill our obligation to serve customers and meet the demands of our counterparty agreements. Some of our generation sources, such as coal, may become obsolete or be prematurely retired through regulatory action or legislation. This could result in higher commodity costs to replace the lost generation, as well as higher costs to retire the generation source before the end of its expected life. This also includes costs (including replacement of lost generation) associated with our transfer of Colstrip ownership to NorthWestern as of January 1, 2026. See "Item 7. Management's Discussion and Analysis—Environmental Issues and Contingencies" for discussion regarding environmental and other issues surrounding Colstrip.

Compliance Risk Factors

There have been numerous changes in legislation, related administrative rulemakings, and Executive Orders, including periodic audits of compliance with such rules, which may adversely affect our operational and financial performance.

We expect to continue to be affected by legislation at the national, state and local level, as well as by administrative rules and requirements published by government agencies, including but not limited to the FERC, the EPA and state regulators. We are also subject to NERC and WECC reliability standards. The FERC, the NERC and the WECC perform periodic audits of the Company. Failure to comply with the FERC, the NERC, or the WECC requirements can result in financial penalties.

Future legislation, administrative rules or Executive Orders could have a material adverse effect on our operations, results of operations, financial condition and cash flows.

Resource Adequacy Risk Factors

Multiple factors are influencing the ability to source and deliver adequate energy to meet customer demand, which could lead to power and gas market liquidity risks.

Local and regional factors may occur and impact our ability to meet energy needs during periods of high demand or unplanned events. Locally, some combination of factors such as unanticipated load growth, unforeseen localized climatic changes, decreases in water availability for hydro generation, and prolonged unplanned generation outages could result in being short the energy we need to meet customer demand. External to localized conditions and events, the regional wholesale market, to which we would turn to purchase energy to meet short-term shortfalls, has become strained during regional events. If the northwest region does not build sufficient new generation capacity and additional transmission and gas transport, there is a risk that we will not be able to depend on excess energy market purchases to meet customer demand during extreme weather events. These factors are increasing the risk of potential regional energy supply shortages and the ability for us to access additional energy during periods of high demand or unplanned events.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of the filing date of this Annual Report on Form 10-K, we have no unresolved comments from the staff of the SEC.

ITEM 1C. CYBERSECURITY

The energy sector, including electric and natural gas utility companies, has become the subject of cyberattacks with increased frequency and we, along with other utility companies, are the target of these frequent attacks. In addition, there is a growing reliance on third party providers which are also subject to attacks and breaches. Any unexpected failure, or unauthorized access to technology systems or third parties relied upon can result in the unavailability of systems or services, which can result in a loss of operating revenues, damage to our brand and reputation, and/or an increase in operating expenses and costs to repair or replace damaged assets. To date, we have not identified any risks from cybersecurity threats that have materially affected or are reasonably likely to materially affect our results of operation or financial condition. See "Risk Factors—Cybersecurity Risk Factors" for further information regarding the risks we face from cybersecurity threats.

We consider the management of cybersecurity risk in our overall enterprise risk management process. See "Item 7. Management's Discussion and Analysis—Enterprise Risk Management" for further discussion of the process.

We mitigate cyber risk by maintaining an enterprise security program based on the National Institute of Standards and Technology Cybersecurity Framework. This program includes trainings and exercises at all levels of the Company. Our security program incorporates enterprise business continuity which facilitates a business impact analysis of core functions for development of emergency operating and disaster recovery plans and coordinates annual testing and training exercises. In addition, there are independent third party and regulatory audits of our security program.

The cybersecurity risk management program is overseen by senior leadership within our Technology and Security functions.

The program is led by the Senior Vice President of Operations and Technology and the Vice President, Chief Information and Security Officer. The Senior Vice President of Operations and Technology has more than 20 years of experience in information technology leadership, including roles directing enterprise systems and cybersecurity programs at other companies. The Vice President, Chief Information and Security Officer has over 15 years of experience at the Company, having served in engineering and technology leadership roles, including as the Director of Information Technology Infrastructure and the Director of Applications. This program includes maintenance of appropriate cybersecurity measures, such as firewalls, anti-virus, patching, and other zero-trust security protocols, monitoring for intrusion and security events that may include a data breach or an attack on our operations, and working with our supply chain department to ensure contracts with third party service providers include appropriate requirements for the mitigation of cybersecurity risk that might impact our business.

Our data breach response team is comprised of designated members of the technology department, senior management and other appropriate individuals. The team is tasked with assessing, managing and responding to material cybersecurity incidents involving either our systems or the systems of third party service providers. The data breach response team includes subject matter experts within the Company, as well as outside experts who specialize in cybersecurity response. A subset of this team is also responsible for assessing the materiality of cybersecurity incidents, reporting to the Audit Committee of the Board of Directors as appropriate, and ensuring timeline reporting of cybersecurity incidents deemed material to the Company.

The Environmental, Technology and Operations Committee of the Board of Directors oversees our management of cybersecurity risks. This Committee is briefed on security policy, programs and incidents on at least a quarterly basis. The Audit Committee of the Board of Directors provides oversight of required disclosures relating to cybersecurity.

ITEM 2. PROPERTIES

AVISTA UTILITIES

Substantially all of Avista Utilities' properties are subject to the lien of Avista Corp.'s mortgage indenture.

Avista Utilities' electric properties, located in the states of Washington, Idaho, Montana and Oregon, include the following:

COMPANY-OWNED GENERATION PROPERTIES

	Present Capability (MW) (1)
Hydroelectric Generating Stations (River)	
Washington:	
Long Lake (Spokane)	88
Little Falls (Spokane)	48
Nine Mile (Spokane)	41
Upper Falls (Spokane)	10
Monroe Street (Spokane)	15
Idaho:	
Cabinet Gorge (Clark Fork) (2)	273
Post Falls (Spokane)	12
Montana:	
Noxon Rapids (Clark Fork)	562
Total Hydroelectric	1,049
Thermal Generating Stations (cycle, fuel source)	
Washington:	
Kettle Falls GS (combined-cycle, wood waste) (3)	53
Kettle Falls CT (combined-cycle, natural gas) (3)	7
Northeast CT (simple-cycle, natural gas)	65
Boulder Park GS (simple-cycle, natural gas)	25
Idaho:	
Rathdrum CT (simple-cycle, natural gas)	166
Montana:	
Colstrip Units 3 & 4 (simple-cycle, coal) (4)	—
Oregon:	
Coyote Springs 2 (combined-cycle, natural gas)	322
Total Thermal	638
Total Generation Properties	1,687

(1) *Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions.*

(2) *For Cabinet Gorge, we have water rights permitting generation up to 265 MW. However, if natural stream flows will allow for generation above our water rights, we are able to generate above our water rights. If natural stream flows only allow for generation at or below 265 MW, we are limited to generation of 265 MW. The present capability disclosed above represents the capability based on maximum stream flow conditions when we are allowed to generate above our water rights.*

(3) *These generating stations can operate as separate single-cycle plants or combined-cycle with the natural gas plant providing exhaust heat to the wood boiler to increase efficiency.*

(4) *Our 15 percent interest in Colstrip was transferred to NorthWestern on January 1, 2026. See "Item 7. Management's Discussion and Analysis of Financial Condition—Colstrip" for information related to Colstrip Units 3 & 4.*

Electric Power Purchase Agreements

Avista Utilities enters into long-term PPAs to purchase a portion or all of the output of specific generation assets. These generating assets are owned by other parties, not the Company, and are not subject to the lien of Avista Corp.'s mortgage indenture. However, these assets are subject to the liens securing the indebtedness of the respective owners. See further discussion of certain of these PPAs in "Part 1—Item 1. Business—Avista Utilities—Electric Operations".

The following is a summary of PPAs as of December 31, 2025:

	Present Capability (MW) (1)	Expiration of Contract
Hydroelectric		
Douglas County PUD	16	2028
Grant County PUD	76	2052
Chelan County PUD (2)	263	2045
Columbia Basin Hydro (3)	103	2045
Total Hydroelectric	458	
Thermal		
Lancaster	276	2041
Wind		
Clearwater Wind	98	2055
Palouse Wind	105	2042
Rattlesnake Flat Wind	144	2040
Total Wind	347	
Solar		
Lind Solar	20	2038
Total Power Purchase Agreements	1,100	

(1) *Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions.*

(2) *Our contracted portion of generation asset output from Chelan County PUD changes throughout the life of the agreement. Our output is expected to increase 88 MW in 2026, decrease 88 MW in 2032, and decrease 88 MW in 2034.*

(3) *Our output from this contract is expected to increase to a total of 147 MW by 2030 as we receive additional capacity under this contract.*

Electric Distribution and Transmission Plant

Avista Utilities owns and operates approximately 20,000 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of approximately 700 miles of 230 kV line and approximately 1,600 miles of 115 kV line. We also own an 11 percent interest in approximately 600 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices and other equipment.

The 230 kV lines are the backbone of our transmission grid and are used to transmit power from generation resources, including Noxon Rapids, Cabinet Gorge and the Mid-Columbia hydroelectric projects, to the major load centers in our service area, as well as to transfer power between points of interconnection with adjoining electric transmission systems. These lines interconnect at various locations with the BPA, Grant County PUD, PacifiCorp, NorthWestern and Idaho Power Company and serve as points of delivery for power from generating facilities outside of our service area, including Colstrip, Coyote Springs 2 and the Lancaster Plant.

These lines also provide a means to optimize resources through short-term purchases and sales of power with entities within and outside of the Pacific Northwest.

The 115 kV lines provide for transmission of energy and the integration of smaller generation facilities with our service-area load centers, including the Spokane River hydroelectric projects, the Kettle Falls projects, Rathdrum CT, Boulder Park GS and Northeast CT. These lines interconnect with the BPA, Chelan County PUD, the Grand Coulee Project Hydroelectric Authority, Grant County PUD, NorthWestern, PacifiCorp and Pend Oreille County PUD. Both the 115 kV and 230 kV interconnections with the BPA are used to transfer energy to facilitate service to each other's customers that are connected through the other's transmission system. We hold a long-term transmission agreement with the BPA that allows us to serve our native load customers that are connected through the BPA's transmission system.

Natural Gas Plant

Avista Utilities has natural gas distribution mains of approximately 3,600 miles in Washington, 2,300 miles in Idaho and 2,400 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 15 miles in Oregon. Our natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

We own a one-third interest in Jackson Prairie, an underground natural gas storage field located near Chehalis, Washington. See "Part 1—Item 1. Business—Avista Utilities—Natural Gas Operations" for further discussion of Jackson Prairie.

ALASKA ELECTRIC LIGHT AND POWER COMPANY

Substantially all of AEL&P's utility properties (except the Snettisham plant) are subject to the lien of the AEL&P mortgage indenture.

AEL&P's utility electric properties, located in Alaska include the following:

	Present Capability (MW) [1]
Hydroelectric Generating Stations	
Snettisham [2]	78
Lake Dorothy	14
Salmon Creek	5
Annex Creek	4
Gold Creek	2
Total Hydroelectric	103
Diesel Generating Stations	
Lemon Creek	52
Auke Bay	25
Gold Creek	7
Industrial Blvd. Plant	23
Total Diesel	107
Total Generation Properties	210

(1) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions.

(2) AEL&P does not own this generating facility and it is not subject to the lien of the AEL&P mortgage indenture. AEL&P has a PPA under which it has the right to purchase, and the obligation to pay for, all the capacity and energy of this facility. See further information at "Part 1. Item 1. Business—Alaska Electric Light and Power Company."

In addition to the generation properties above, AEL&P owns 61 miles of transmission lines, which are primarily comprised of 69 kV line, and 184 miles of distribution lines.

ITEM 3. LEGAL PROCEEDINGS

See "Note 22 of Notes to Consolidated Financial Statements" for information with respect to legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AVISTA CORP. MARKET INFORMATION AND DIVIDEND POLICY

Avista Corp.'s common stock is listed on the New York Stock Exchange under the ticker symbol "AVA." As of January 31, 2026, there were 5,541 registered shareholders of our common stock.

Avista Corp.'s Board of Directors considers the level of dividends on our common stock on a recurring basis, taking into account numerous factors including, without limitation:

- our results of operations, cash flows and financial condition,
- the success of our business strategies, and
- general economic and competitive conditions.

Avista Corp.'s net income available for dividends is generally derived from our regulated utility operations (Avista Utilities and AEL&P).

The payment of dividends on common stock could be limited by:

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements (see "Item 7. Management's Discussion and Analysis—Capital Resources" for compliance with these covenants),
- the hydroelectric licensing requirements of section 10(d) of the FPA (see "Note 1 of Notes to Consolidated Financial Statements"), and
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Utilities to maintain a capital structure of no less than 35 percent common equity (including short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC.

For additional information, see "Notes 1 and 19 of Notes to Consolidated Financial Statements."

For information with respect to securities authorized for issuance under equity compensation plans, see "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters."

ITEM 6. [REMOVED AND RESERVED]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This section of this Annual Report on Form 10-K generally discusses financial statement items and comparisons between 2025 and 2024. Discussion of 2023 financial statement items and comparisons between 2024 and 2023 not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Conditions and Results of Operations" in Part II, Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2024.

BUSINESS SEGMENTS

As of December 31, 2025, we have two reportable business segments, Avista Utilities and AEL&P. We also have other businesses which do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp. See "Part I, Item 1. Business—Company Overview" for further discussion of our business segments.

The following table presents net income (loss) for each of our business segments and the other businesses, for the year ended December 31 (dollars in millions):

	2025	2024	2023
Avista Utilities	$ 201	$ 179	$ 167
AEL&P	6	8	9
Other non-reportable segment loss	(14)	(7)	(5)
Net income	$ 193	$ 180	$ 171

EXECUTIVE OVERVIEW

Overall Results

Net income increased primarily due to the effects of general rate cases. This increase in earnings was partially offset by increases in other operating expenses, depreciation and amortization expense, taxes other than income taxes and interest expense. The increase in net income was also partially offset by a $9 million refund to be issued to customers for adjustments related to Colstrip investments. See "Regulatory Matters" for further details regarding the Colstrip final order. In addition, increased investment losses associated with lower valuations of certain investments in our portfolio decreased net income at our other businesses when compared to 2024.

More detailed explanations of the fluctuations are provided in the results of operations and business segment discussions (Avista Utilities, AEL&P, and the other businesses) that follow this summary.

Resource Adequacy

Extreme weather events, both in summer and winter, have occurred in the Pacific Northwest. These events have resulted in system load peaks that were higher than anticipated. Historically, we have had excess capacity as compared to peak load, but during some extreme events, we have had to purchase short-term energy from the wholesale market to meet demand when our energy resources were not operating at full capacity or were otherwise unavailable. These weather events have highlighted the growing need for additional generating capacity both on our system and in the Pacific Northwest region.

The transition to clean energy (including the replacement of emitting facilities with non-emitting facilities, which are impacted by conditions outside of our control), and electrification, combined with expected load growth, and the transfer of our interest in Colstrip, also factor into the need for additional generation.

We also see the need for expanded transmission infrastructure to provide access to additional resources and improve reliability in our region. In November 2024, we signed a non-binding memorandum of understanding to join the North Plains Connector transmission line project that plans to construct a transmission line from Bismarck, North Dakota to Colstrip, Montana.

Current Hydroelectric Conditions and Outlook

Due to precipitation and warm weather, our hydroelectric generation in January and February (to date) has been above normal. Due to the warm weather, the average current level of snowpack in the areas serving our hydroelectric facilities is below normal. The amount of hydroelectric generation over the rest of the year will be affected not only by current snowpack levels but also by prevailing temperatures (which affect the timing and speed of run-off) and the volume, timing and form of precipitation. On balance, we expect the amount of hydroelectric generation for the entire year will be approximately at the normal level. While our current hydro forecast shows normal levels of generation, even if we were above or below normal, there would be no material change to our position in the ERM.

2025 Request for Proposal (RFP)

Our 2025 electric IRP was filed with the WUTC and IPUC in December 2024, and identified needs for additional generating capacity. In May 2025, we issued a request for proposal to add energy and capacity to meet projected resource needs. We selected a list of projects and will begin contract negotiations for the following:

- a self-build upgrade of our existing Natural Gas Combustion Turbines at Rathdrum CT to add 14 MW of capacity without increasing carbon emissions. This upgrade will occur in two stages with the first occurring in 2027 and the second in 2029,
- a project for 100 MW, 4-hour Battery Energy Storage System, to be built and transferred to the Company in eastern Washington with a target date in 2028,
- a PPA for approximately 200 MW of wind power from Montana that utilizes our share of the Colstrip Transmission System with a target date in 2029, and
- the addition of approximately 40 MW of Demand Response Programs that will recruit residential, commercial and industrial customers within our service territory, beginning in 2026.

See "Part 1—Item 1. Business—Future Electric Resource Needs" for further discussion of regional resource adequacy.

2026 Customer Load

We expect a decrease in customer load from 2025 to 2026 to have a negative impact on our 2026 results. This decrease in load is associated with a large industrial customer with their own transmission rights and access to procure their own energy independently. We were notified of this customer's intent to return to procuring their power independently in the power markets effective April 2026, which is earlier than we had expected. Net income is expected to decrease $9 million compared to if we had served their load through December 2026.

Colstrip

In December 2025, the WUTC issued a final order for our filed tariff rider for Colstrip and on January 1, 2026, the transaction to transfer our 15 percent ownership in Colstrip Units 3 & 4 to NorthWestern closed. See "Colstrip" section and "Note 22 of the Notes to Consolidated Financial Statements" for further details on the exit of Colstrip through an agreement with NorthWestern and "Regulatory Matters" for further details regarding the Colstrip final order.

Tariffs on Imports

The President of the United States of America has imposed tariffs on certain imported goods. The imposition of tariffs may impact the cost of other equipment and materials that are critical to our business, increasing capital and operating expenses, and could create supply chain disruptions. The tariffs have not had a material impact on our operations or financial performance to date. At this time, we do not expect the impact of tariffs to be material and have not made any adjustments to our capital or operating budget to account for increased costs resulting from tariffs.

We import a significant amount of natural gas from Canada, both to serve our retail natural gas customers and as fuel for electric generation. We do not expect these imports to be impacted by the current trade tariffs as they are covered by the U.S.-Mexico-Canada Agreement, but the future of trade tariffs on energy commodity imports is uncertain. The impact of an increase in resource costs on our results of operations (directly or indirectly resulting from tariffs) would be substantially mitigated by various deferral and recovery mechanisms (ERM, PCA, and PGAs), but there could be an immediate impact on our cash flow.

In February 2026, the United States Supreme Court ruled that the legal basis cited by the President for the imposition of tariffs is not valid, and that he is restricted from imposing tariffs in the absence of a clear grant of authority from the Legislature. The impact of the Court's ruling, both as to tariffs already collected and as to potential future tariffs, is uncertain at this time.

We are closely monitoring the impacts of tariffs and the potential impact they may have on our results of operations, financial condition and cash flows.

U.S. Reconciliation Bill

In July 2025, the One Big Beautiful Bill Act (OBBB) was signed into law, which includes significant changes to the U.S. tax code and related laws. Key provisions include modifications and extensions to certain provisions of the Tax Cuts and Jobs Act of 2017 and updates to energy-related tax incentives, including revisions to the Clean Electricity Production Credit and the investment tax credit, as well as restrictions related to support from prohibited foreign entities. OBBB also allows for the current expensing of certain specified research and experimental (Section 174) expenditures.

The OBBB did not have a material impact on our results of operations and financial condition in 2025. We continue to monitor ongoing guidance. Any future impacts will be recognized in the period in which they become known. See "Note 13 of the Notes to Consolidated Financial Statements" for further discussion of the impact of OBBB.

Enterprise Resource Planning (ERP) Project

We are planning to implement an ERP system, replacing certain existing technology tools currently in use. The system will be designed to accurately maintain our financial records, enhance operational functionality, and provide timely information to our management team related to business operations. Accounting petitions were filed with the WUTC, the IPUC and the OPUC related to the project. These petitions include requesting to defer the undepreciated technology assets being replaced and a 15 year depreciable life for implementation costs. The requests were materially approved by the commissions.

We entered into a contract with a software provider and are in negotiations with system implementers. We expect the ERP system to be implemented in 2028. We expect capital expenditures between $100 million to $130 million.

Regulatory Lag

Regulatory lag is inherent in utility ratemaking; a result of the delay between the investment in utility plant and/or the increase in costs and the receipt of an order of a public utility commission authorizing an increase in rates sufficient to recover such investment or costs. Regulatory lag can be mitigated to some extent by the incorporation of reasonably expected forward-looking information into an authorization of increased rates. However, there is no protection against unexpected inflation and increased interest rates. See "Regulatory Matters" for additional discussion of the general rate cases.

REGULATORY MATTERS

General Rate Cases

We regularly review the need for electric and natural gas rate changes in each state in which we provide service. We will continue to file for rate adjustments to:

- seek recovery of operating costs and capital investments, and
- seek the opportunity to earn reasonable returns as allowed by regulators.

The assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, but are not limited to, in-service dates of major capital investments and the timing of changes in major revenue and expense items.

Avista Utilities

Washington General Rate Cases

2024 General Rate Cases

In December 2024, the WUTC issued orders related to our multi-year electric and natural gas general rate cases filed with the WUTC in January 2024.

The approved rates within the orders were designed to increase annual electric base revenues by $12 million (or 2.0 percent), effective January 1, 2025 (Rate Year 1), and $44 million (or 7.5 percent) for Rate Year 2. The difference in approved rates for Rate Year 1 and those included in our original request of $77 million is primarily due to a $56 million decrease in power supply costs compared to those set forth in the original request, and also due to a lower approved return on equity than requested. The Rate Year 2 increase represents the effective increase to customers resulting from the $69 million approved in the order, partially offset by a $25 million decrease due to the expiration of a separate tariff in effect during Rate Year 1 to collect remaining Colstrip expenses by December 31, 2025 (see further discussion below).

The approved rates were also designed to increase annual natural gas base revenues by $14 million (or 11.2 percent), effective January 1, 2025, and $4 million (or 2.8 percent) for Rate Year 2.

The WUTC approved an ROE of 9.8 percent, based on a common equity ratio of 48.5 percent, and an ROR of 7.32 percent.

The WUTC did not approve our request to modify the ERM under which differences between actual net power supply costs and the amount reflected in base retail customer rates are tracked. Our actual net power supply costs exceeded the amount reflected in base retail customer rates by $78 million in 2025, and we expect actual net power supply costs to significantly exceed the level included in base rates in 2026. We plan to continue to address how net power supply costs are set in base rates in future regulatory proceedings. See Note 23 for further details of the ERM and other power cost deferrals and recovery mechanisms.

The Commission continued its support for important recovery mechanisms such as wildfire and insurance balancing accounts, and decoupling.

2026 General Rate Cases

On January 16, 2026, we filed an MYRP with the WUTC.

The MYRP requests base rate relief over four years designed to produce the additional base revenues shown below (dollars in millions):

Rate Year	Rates Effective	Electric			Natural Gas		
1	2027	$	111	13.9%	$	12	4.7%
2	2028		43	4.7%		7	2.4%
3	2029		34	3.5%		6	2.1%
4	2030		28	2.8%		3	1.1%

We requested an overall rate of return in 2027 of 7.5 percent, with a 48.5 common equity ratio and a 10.2 percent return on equity. We requested an increase to the overall rate of return in 2029 to 7.67 percent, with a 48.5 common equity ratio and 10.5 percent return on equity.

Key drivers of the revenue requirement in rate year one (2027) are outlined below (dollars in millions):

	Electric		Natural Gas	
Electric resource costs	$	46	$	—
Capital additions		29		5
Employee benefits		7		1
Insurance		7		—
Regulatory amortizations		5		4
Wildfire		4		—
Other		13		2
Total	$	111	$	12

In the MYRP, we propose certain changes to the calculation of authorized baseline power supply costs. These changes are designed to address the changing market dynamics which have led to significant volatility in actual power supply costs. The MYRP provides updates to our baseline power supply cost for rate years one and two; as required by Washington law, baseline power supply costs for rate years 3 and 4 will be established in later filings and as such are not included in the additional revenue requirements for those years shown above. In addition, we are proposing changes to the timing for recovery of costs deferred under the Energy Recovery Mechanism.

In addition to requesting re-approval of existing insurance, wildfire, and decoupling deferral accounts, we are proposing an additional deferral mechanism for costs associated with employee benefits.

Washington law requires utilities to file MYRPs of a minimum of 2 and up to 4 years. The law allows utilities filing a rate plan of 3 or 4 years the option to file a new rate plan for the third year and fourth year. Under this provision, we have the opportunity to address the numerous unpredictable factors that could materially affect our financial position over a longer-term rate plan. These risks include, but are not limited to, inflation, interest rate volatility, labor and benefits challenges, escalating capital costs, and other unforeseen cost drivers. See "Item 1A: Risk Factors" for a full discussion of these factors.

The WUTC has up to eleven months to review the general rate case filings and issue a decision.

Colstrip Tariff

In 2019, the Washington State Legislature passed the CETA, which, among other things, requires costs associated with coal-fired generation facilities to be removed from rates no later than December 31, 2025. The WUTC order approving the settlement of the 2022 general rate cases, required us to establish a tracker for our Colstrip-related costs, including operating and maintenance expense, depreciation and amortization expense, and a return on rate base. In October 2024, we filed a cost recovery tariff seeking to recover the costs associated with our ownership of Colstrip in 2025. In the filing, we requested an increase in annual Colstrip tariff revenues of $19 million—from $24 million in 2024 to $43 million in 2025, effective January 1, 2025. In its review, WUTC Staff raised concerns related to (1) whether forecasted 2025 investments are allowed in rates; (2) whether the capital investment included in the filing will be used and useful for customers prior to the end of 2025; and (3) one major capital investment that will not be in service until 2027. In December 2024, the WUTC allowed our filed tariff to go into effect, but set the rates as subject to refund. A final order was issued in December 2025, which determined that certain investments in Colstrip were not used or useful to our customers after December 31, 2025, and as such should be prorated or disallowed. As a result, we are required to issue a refund to customers of $9 million, either in a lump sum or spread over up to three months. We are required to file a compliance filing by March 31, 2026 detailing the 2025 Colstrip investments and customer refunds.

Idaho General Rate Cases

2023 General Rate Cases

In August 2023, the IPUC approved the multi-party settlement agreement designed to increase annual base electric revenues by $22 million, or 8.0 percent, effective in September 2023, and $4 million, or 1.4 percent, effective in September 2024. The agreement was designed to increase annual base natural gas revenues by $1 million, or 2.7 percent, effective in September 2023, and a negligible increase effective in September 2024.

The settlement was based on an ROE of 9.4 percent, with a common equity ratio of 50 percent, and an ROR of 7.19 percent.

2025 General Rate Cases

In August 2025, the IPUC approved the all-party settlement agreement designed to increase annual base electric revenues by $20 million, or 6.3 percent, effective September 2025, and $15 million, or 4.5 percent, effective September 2026. For natural gas, the agreement was designed to increase annual base natural gas revenues by $5 million, or 9.2 percent, effective September 2025, and decrease annual base natural gas revenues by $0.2 million, or 0.4 percent, effective September 2026.

The settlement was based on an ROE of 9.6 percent with a common equity ratio of 50 percent and an ROR of 7.28 percent.

Oregon General Rate Cases

2024 General Rate Case

In May 2025, the OPUC approved the all-party settlement agreement designed to increase annual base revenues by $4 million, or 5.0 percent, effective in September 2025. The settlement was based on an ROE of 9.5 percent with a common equity ratio of 50 percent and an ROR of 7.22 percent.

To mitigate the overall impact of the revenue increases on customers, $5 million of tax customer credits will be accelerated and returned to customers over a three-year period.

Future Oregon General Rate Cases

In July 2025, the Governor of Oregon signed House Bill 3179 into law which modifies certain provisions of law that relate to general rate case filings and cost recovery. The law, among other things, extends the length of time for the commission to suspend rates from a proposed effective date from nine to ten months, does not allow residential rate increases of any kind between November 1 and March 31, does not allow new rates to take effect from a proceeding where the return on equity is at issue within eighteen months of the prior rate effective date, authorizes (but does not require) securitization of "capital investments" that will cause rates to "rise by more than five percent" under specific circumstances, and calls for the OPUC to establish rules requiring utilities to establish a multiyear rate plan for rate revisions where a company's return on equity is reviewed. Such rate plans must be no less than three years and no more than seven years in length. Rulemakings to institute these provisions started in September 2025 and will continue through 2026. We are analyzing the possible effects of this legislation, including how it will impact the timing of future rate case filings.

Power Cost Deferrals, Decoupling, Earnings Sharing Mechanisms, and Purchased Gas Adjustments

See "Note 23 of the Notes to Consolidated Financial Statements" for discussion of these regulatory mechanisms.

Alaska Electric Light and Power Company

2022 General Rate Case

In August 2023, the RCA issued a final order related to AEL&P's electric general rate case, which was originally filed in July 2022.

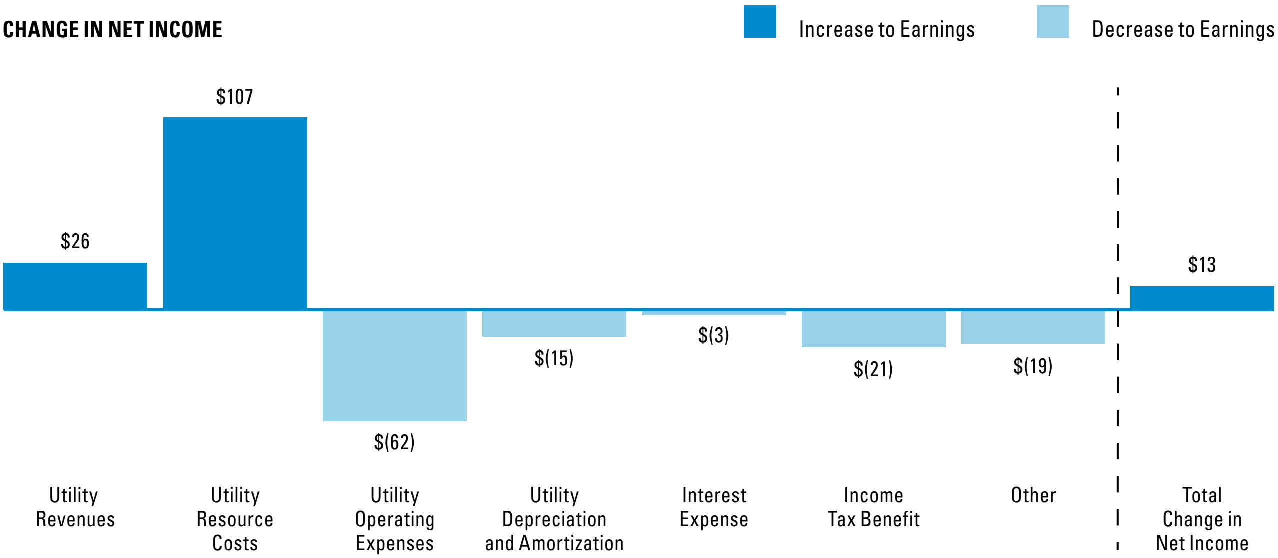
The order reflected an ROE of 11.45 percent, a common equity ratio of 60.7 percent, and an ROR of 8.79 percent. AEL&P is required to file its next general rate case by August 2027.

RESULTS OF OPERATIONS—OVERALL

The following provides an overview of changes in our Consolidated Statements of Income. More detailed explanations are provided, particularly for operating revenues and operating expenses, in the business segment discussions (Avista Utilities, AEL&P and the other businesses) that follow this section.

2025 compared to 2024

The following graph shows the total change in net income for 2025 to 2024, as well as the various factors that caused such change (dollars in millions):



Utility revenues increased as a result of the effects of general rate cases and customer and load growth. This was partially offset by decreased wholesale revenues associated with decreased electric sale prices, as well as decreases in natural gas rates associated with the PGA regulatory mechanism, which do not impact utility margin or net income. Additionally, the increase in electric revenue was partially offset by a refund to be issued to customers for adjustments related to Colstrip investments. See "Regulatory Matters" for further details regarding the Colstrip final order.

Electric utility resource costs decreased primarily due to decreased purchased power costs associated with decreased wholesale prices, as well as decreased amortizations of previously deferred costs. Electric utility resource costs also decreased due to the effects of the Washington general rate case and a lower level of authorized power supply costs resulting in increased deferrals of power supply costs. Natural gas utility resource costs decreased due to decreased commodity prices, as well as decreased amortization of previously deferred PGA costs. These decreases were offset by an increase in the amortization of costs associated with the CCA that are being recovered from customers.

Utility operating expenses increased due to increased employee salaries and benefits costs. In addition, net amortizations and deferrals associated with wildfire mitigation and insurance costs have increased, with corresponding increases to revenue which result in no impact to net income.

Utility depreciation and amortization increased primarily due to additions to utility plant.

Income tax expense increased primarily due to the decrease in tax customer credits which offset the bill impact of rate increases included in our prior general rate cases. Income tax expense also increased due to increased pre-tax net income compared to the prior year. See "Note 13 of the Notes to Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

The decrease in earnings related to other is primarily due to increased net investment losses compared to the prior year. In addition, non-utility operating expenses increased due to updated estimates for an existing environmental remediation liability at one of our subsidiaries, which resulted in a pre-tax expense of $3 million in 2025.

NON-GAAP FINANCIAL MEASURES

The following discussion for Avista Utilities includes two financial measures that are considered "non-GAAP financial measures," electric utility margin and natural gas utility margin. In the AEL&P section, we also include a discussion of electric utility margin.

Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. Electric utility margin is electric operating revenues less electric resource costs, while natural gas utility margin is natural gas operating revenues less natural gas resource costs. The most directly comparable GAAP financial measure to electric and natural gas utility margin is utility operating revenues as presented in "Note 24 of the Notes to Consolidated Financial Statements."

The presentation of electric utility margin and natural gas utility margin is intended to enhance understanding of our operating performance. We use these measures internally and believe they provide useful information to investors in their analysis of how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. Changes in loads, as well as power and natural gas supply costs, are generally deferred and recovered from customers through regulatory accounting mechanisms. Accordingly, the analysis of utility margin generally excludes most of the change in revenue resulting from these regulatory mechanisms. We present electric and natural gas utility margin separately below for Avista Utilities since each portion of our business has different cost sources, cost recovery mechanisms and jurisdictions, so we believe that separate analysis is beneficial. These measures are not intended to replace utility operating revenues as determined in accordance with GAAP as an indicator of operating performance. Reconciliations of operating revenues to utility margin are set forth below.

RESULTS OF OPERATIONS—AVISTA UTILITIES

Resource Optimization

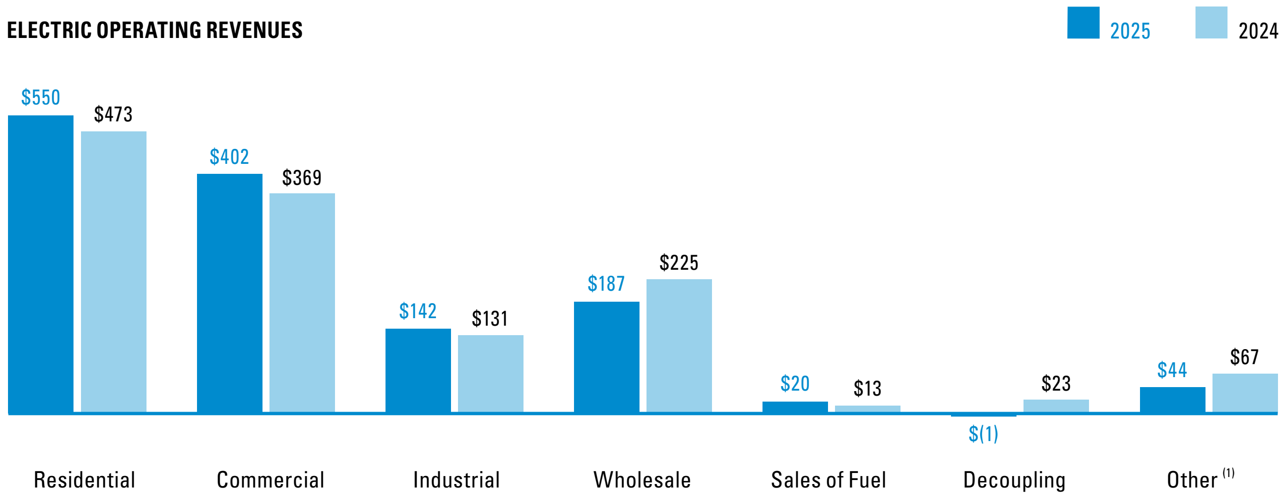
We engage in resource optimization, which involves the selection from available energy resources to serve our load obligations and the use of these resources to capture economic value through wholesale market transactions, which is ultimately intended to lower net power and natural gas supply costs. Our resource optimization transactions can take the form of physical sales and purchases of electric capacity and energy and fuel for electric generation, purchases and sales of natural gas to optimize use of pipeline and storage capacity, as well as derivative transactions related to capacity, energy, fuel and fuel transportation. See Item 1. "Business—Avista Utilities—Electric Operations—General" and "Business—Avista Utilities—Natural Gas Operations—General".

We typically enter into multiple transactions simultaneously to capture value. Even though these transactions are considered together when determining the net impact, they are recorded in separate items within components of utility operating revenue and resource costs and can cause fluctuations in each item. Gains and losses on derivative contracts are included in certain line items below (such as wholesale sales and purchases of power and natural gas, sales of fuel, and other fuel costs). The ERM, PCA and PGAs are based on net supply costs and consider all transactions related to resource procurement and optimization (both physical and financial).

2025 compared to 2024

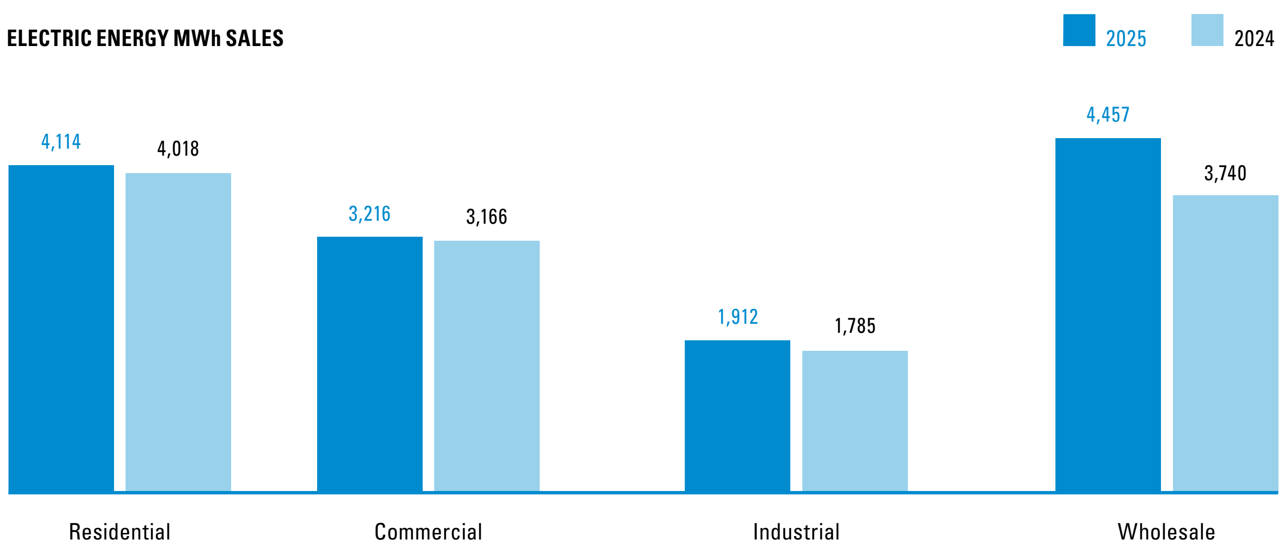
Utility Operating Revenues

The following graphs present Avista Utilities' electric operating revenues and MWh sales for 2025 and 2024, respectively (dollars in millions and MWhs in thousands):



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues, and deferrals/amortizations to customers related to federal income tax law changes.

Total electric operating revenues in the graph above include intracompany sales of $3 million and $4 million for 2025 and 2024, respectively.



The following table presents the current year decoupling deferrals and the amortization of prior year decoupling deferrals reflected in utility electric operating revenues for the years ended December 31 (dollars in millions):

	Electric Decoupling Revenues	
	2025	2024
Current year decoupling deferrals [(a)]	$ —	$ 5
Amortization of prior year decoupling deferrals [(b)]	(1)	18
Total electric decoupling revenue	$ (1)	$ 23

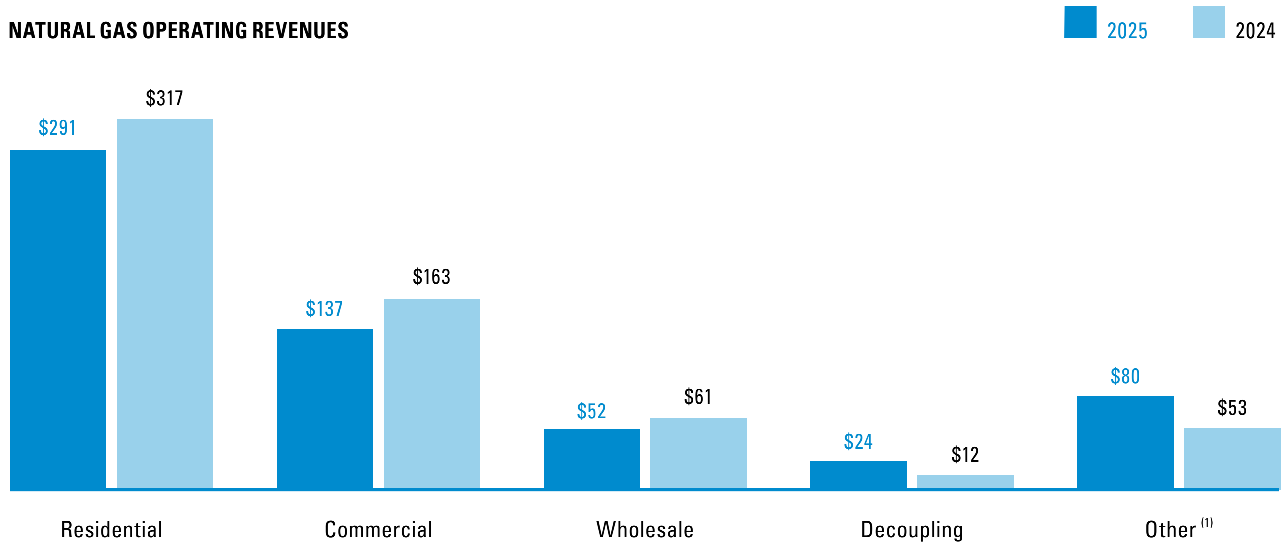
(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total electric revenues increased $43 million for 2025 as compared to 2024. The primary differences in the results for these periods were as follows:

- a $122 million increase in retail electric revenues due to an increase in revenue per MWh (increased revenues $90 million), and an increase in total MWhs sold (increased revenues $32 million).
  - retail rates increased mainly due to the effects of our general rate cases.
  - retail sales volumes increased primarily due to customer growth.
- a $38 million decrease in wholesale electric revenues due to decreases in prices in the wholesale market (decreased revenues $68 million), partially offset by an increase in sales volumes (increased revenues $30 million). The change in volumes was due to increased opportunities to optimize our generation assets based on market conditions.
- a $24 million decrease in electric decoupling revenue, primarily due to decreases of amortizations of prior year rebate balances compared to 2024. In addition, deferrals of surcharge balances decreased compared to 2024.
- a $23 million decrease in other electric revenues, primarily resulting from a $9 million refund to be issued to customers for adjustments related to Colstrip investments, as well as decreased transmission and REC revenues.

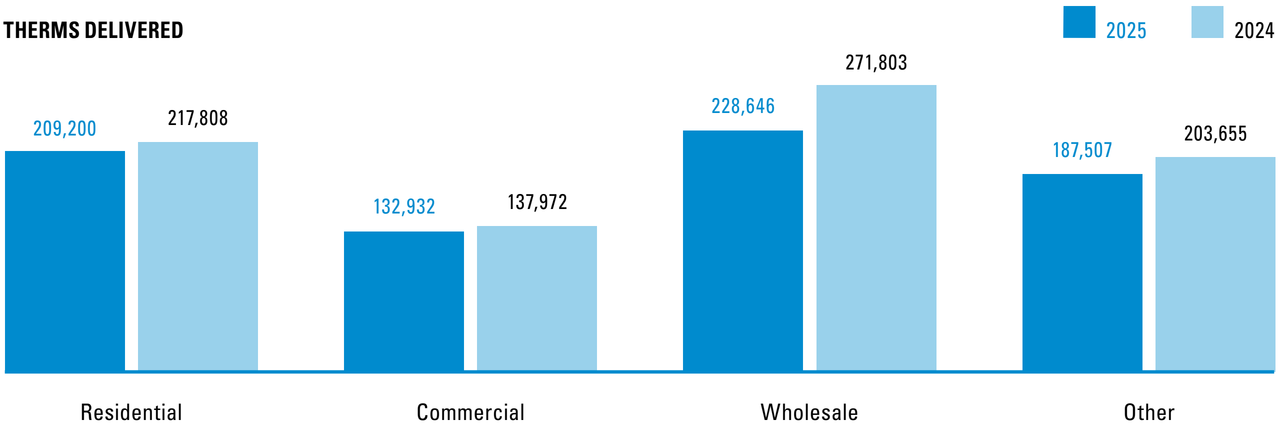
The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for 2025 and 2024, respectively (dollars in millions and therms in thousands):



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues, and deferrals/amortizations to customers related to federal income tax law changes.

Total natural gas operating revenues in the graph above include intracompany sales of $9 million and $16 million for 2025 and 2024, respectively.

THERMS DELIVERED



The following table presents the current year decoupling deferrals and the amortization of prior year decoupling balances reflected in natural gas operating revenues for the years ended December 31 (dollars in millions):

	Natural Gas Decoupling Revenues	
	2025	2024
Current year decoupling deferrals [a]	$ 30	$ 15
Amortization of prior year decoupling deferrals [b]	(6)	(3)
Total natural gas decoupling revenue	$ 24	$ 12

(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

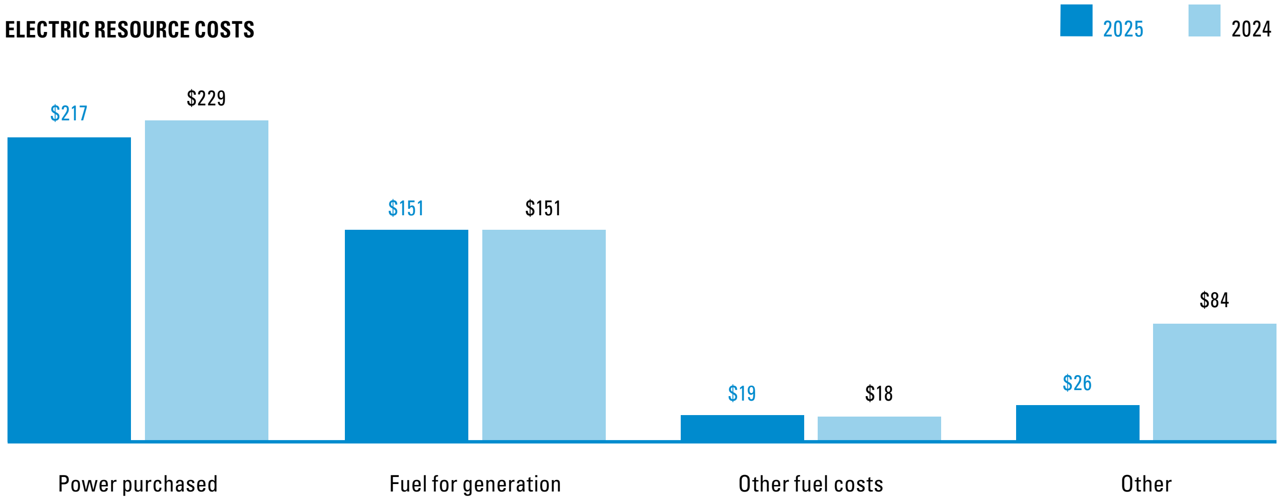
(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts are decreases in decoupling revenue in the current year and are related to the amortization of surcharge balances that resulted in prior years and are being surcharged to customers (causing a corresponding increase in retail revenue from customers) in the current year.

Total natural gas revenues decreased $22 million for 2025 as compared to 2024. The primary differences in the results for these periods were as follows:

- a $53 million decrease in retail natural gas revenues (including industrial, which is included in other) due to decreased retail rates (decreased revenues $43 million) and decreased sales volumes (decreased revenues $10 million). Retail rates decreased due to PGA rate decreases (which do not impact utility margin), partially offset by the effects of our general rate cases and net rate increases associated with the CCA. Residential use per customer decreased 5 percent and commercial use per customer decreased 4 percent compared to 2024 due to warmer weather in the fourth quarter.
- a $9 million decrease in wholesale natural gas revenues due to a decrease in volumes (decreased revenues $10 million), partially offset by an increase in prices in the wholesale market (increased revenues $1 million).
- a $12 million increase in decoupling revenues primarily due to increased surcharge deferrals in the current year resulting from lower customer usage.
- a $27 million increase in other natural gas revenues primarily due to the amortization of previously deferred revenues associated with the sale of CCA emissions credits. We amortize the deferred revenues as they are passed on to customers through decreases in retail rates. The increase in other revenues was offset by decreased retail rates, resulting in no impact to utility margin, and a provision for earnings sharing related to natural gas operations in Washington, which resulted in a refund to be issued to customers.

Utility Resource Costs

The following graph presents Avista Utilities' electric resource costs for 2025 and 2024, respectively (dollars in millions):

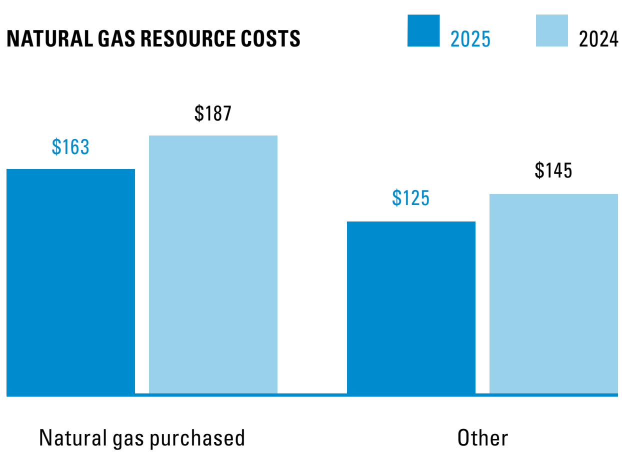


Total electric resource costs in the graph above include intracompany resource costs of $9 million and $16 million for 2025 and 2024, respectively.

Total electric resource costs decreased $69 million for 2025 as compared to 2024. The primary differences in the results for these periods were as follows:

- a $12 million decrease in power purchased due to a decrease in prices in the wholesale market (decreased costs by $51 million), partially offset by an increase in the volume of power purchases (increased costs by $39 million). Prices during the first quarter of 2024 were elevated due to extreme cold temperatures in our region that created capacity constraints.
- a $58 million decrease in other electric resource costs, primarily related to an increase in deferred costs, as well as a decrease in the amortization of previously deferred costs. The increase in deferred costs was primarily due to the effects of the Washington general rate case and a lower level of authorized power supply costs. This was partially offset by increased costs related to our customer assistance payment programs (low-income rate assistance and demand side management).

The following graph presents Avista Utilities' natural gas resource costs for 2025 and 2024, respectively (dollars in millions):



Total natural gas resource costs in this graph include intracompany resource costs of $3 million and $4 million for 2025 and 2024, respectively.

Total natural gas resource costs decreased $44 million for 2025 as compared to 2024. The primary differences in the results for these periods were as follows:

- a $24 million decrease in natural gas purchased due to a decrease in the volume of purchases (decreased costs by $14 million) and a decrease in prices of natural gas in the wholesale market (decreased costs by $10 million).
- a $20 million decrease in other costs, primarily due to a decrease in amortizations of previously deferred costs under our PGAs, partially offset by increased amortization of costs associated with the CCA that were recovered from customers (resulting in no impact to utility margin) and an increase in costs related to our customer assistance payment programs (low-income rate assistance and demand side management).

Utility Margin

The following table reconciles Avista Utilities' operating revenues, as presented in "Note 24 of the Notes to Consolidated Financial Statements", to the Non-GAAP financial measure utility margin for the years ended December 31 (dollars in millions):

	Electric		Natural Gas		Intracompany		Total	
	2025	2024	2025	2024	2025	2024	2025	2024
Operating revenues	$ 1,344	$ 1,301	$ 584	$ 606	$ (12)	$ (20)	$ 1,916	$ 1,887
Resource costs	413	482	288	332	(12)	(20)	689	794
Utility margin	$ 931	$ 819	$ 296	$ 274	$ —	$ —	$ 1,227	$ 1,093

Electric utility margin increased $112 million and natural gas utility margin increased $22 million.

Electric utility margin increased primarily due to the effects of general rate cases, customer growth, and non-decoupled load growth, partially offset by a $9 million refund to be issued to customers for adjustments related to Colstrip investments. See "Regulatory Matters" for further details regarding the Colstrip final order. Natural gas utility margin increased primarily due to the effects of general rate cases.

In 2025 and 2024, we had a pre-tax expense under the ERM of $14 million and $8 million, respectively. The increase is due to the lower level of base net power supply costs established in the most recent Washington general rate case.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of total results for Avista Utilities and in the consolidated financial statements but are included in the separate results for electric and natural gas presented above.

RESULTS OF OPERATIONS—ALASKA ELECTRIC LIGHT AND POWER COMPANY

2025 compared to 2024

Net income for AEL&P was $6 million for 2025, compared to $8 million for 2024.

The following table presents AEL&P's operating revenues, resource costs and resulting utility margin for the years ended December 31 (dollars in millions):

	Electric	
	2025	2024
Operating revenues	$ 47	$ 50
Resource costs	2	4
Utility margin	$ 45	$ 46

Utility margin decreased in 2025 primarily due to lower sales volumes. The decrease in utility margin resulted in a decrease in net income in 2025 compared to 2024. Utility margin is a non-GAAP financial measure. See "Non-GAAP Financial Measures."

RESULTS OF OPERATIONS—OTHER BUSINESSES

2025 compared to 2024

Our other businesses had a net loss of $14 million for 2025 compared to a net loss of $7 million for 2024. The fluctuation in results is primarily related to higher net investment losses. Approximately 75 percent of investment losses in 2025 were related to investments in clean technology. That sector was negatively impacted by shifting public policy and sentiment, leading to decreased valuations of underlying holdings in these investments. Approximately 25 percent of investment losses in 2025 were due to dilution of our ownership percentage resulting from issuance of new shares.

In 2025, we updated our estimates for an existing environmental remediation liability at one of our subsidiaries, which resulted in a pre-tax expense of $3 million.

ACCOUNTING STANDARDS TO BE ADOPTED IN 2026

We are not expecting the adoption of accounting standards to have a material impact on our financial condition, results of operations and cash flows in 2026. For more information on accounting standards expected to be adopted in future periods, see "Note 2 of the Notes to the Consolidated Financial Statements".

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of our consolidated financial statements in conformity with GAAP requires the use of estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and require the use of estimates and assumptions:

- **Regulatory accounting,** in accordance with ASC Topic 980, *Regulated Operations*, among other things, requires that costs and/or obligations that, in our judgment, are probable of recovery through rates charged to customers, but are not yet reflected in rates, not be reflected in our Consolidated Statements of Income until the period in which they are reflected in rates and matching revenues are recognized. Meanwhile, these costs and/ or obligations are deferred and reflected on our Consolidated

Balance Sheets as regulatory assets or liabilities. We generally receive regulatory orders before deferring costs as regulatory assets and liabilities; however, in certain instances in which we have regulatory precedent, we may not request an order before deferring the costs. If, due to changed circumstances, we no longer met the criteria to apply regulatory accounting or if we were no longer allowed to recover these costs, we would be required to recognize significant write-offs of regulatory assets and liabilities in the Consolidated Statements of Income. See "Notes 1, 4 and 23 of the Notes to Consolidated Financial Statements" for further discussion of our regulatory accounting policy and mechanisms.

- **Pension plans and other postretirement benefit plans,** discussed in further detail below.
- **Equity investments,** specifically valuations performed to determine the fair value of certain investment holdings, require judgment in the selection of assumptions used to estimate fair value of investments for which there is not a quoted active market price. We primarily use a market approach to determine fair value of an investment, and transactions involving comparable securities may need to be adjusted to estimate our investment's fair value. See "Notes 7 and 18 of the Notes to Consolidated Financial Statements" for further discussion of our equity investments and method for determining their fair value.
- **Contingencies,** related to unresolved regulatory, legal and tax issues as to which there is inherent uncertainty for the ultimate outcome of the respective matter. We accrue a loss contingency if it is probable that an asset is impaired or a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. To the extent material, we also disclose losses that do not meet these conditions for accrual, if there is a reasonable possibility that a potential loss may be incurred. For all material contingencies, we have made a judgment as to the probability of a loss occurring and as to whether or not the amount of the loss can be reasonably estimated. However, no assurance can be given as to the ultimate outcome of any contingency. See "Notes 1 and 22 of the Notes to Consolidated Financial Statements" for further discussion of our commitments and contingencies.

Pension Plans and Other Postretirement Benefit Plans—Avista Utilities

We have a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities hired prior to January 1, 2014 and regular full-time union employees that were hired prior to January 1, 2024. See "Note 12 of the Notes to Consolidated Financial Statements" for further discussion of these individual plans.

Pension cost (including the SERP) was $11 million for 2025, $7 million for 2024 and $9 million for 2023. Of our pension cost (excluding the SERP), approximately 55 percent is expensed and 45 percent is capitalized consistent with labor charges. The cost related to the SERP is expensed. Our cost for the pension plan is determined in part by actuarial formulas that are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension cost is affected by, among other things:

- employee demographics (including age, compensation and length of service by employees),
- the amount of cash contributions to the pension plan,
- the actual return on pension plan assets,
- expected return on pension plan assets,
- discount rate used in determining the projected benefit obligation and pension costs,
- assumed rate of increase in employee compensation,
- life expectancy of participants and other beneficiaries, and
- expected method of payment (lump sum or annuity) of pension benefits.

We make estimates and assumptions as to many of these factors. In accordance with accounting standards, changes in pension plan obligations associated with these factors may not be immediately recognized as pension costs in our Consolidated Statements of Income, but we generally recognize the change in future years over the remaining average service period of pension plan participants. As such, our cost recorded in a period may not reflect the actual level of cash benefits provided to pension plan participants.

We revise the key assumption of the discount rate each year. In selecting a discount rate, we consider yield rates at the end of the year for highly rated corporate bond portfolios with cash flows from interest and maturities similar to the expected payout of pension benefits.

The expected long-term rate of return on plan assets is reset or confirmed annually based on past performance and economic forecasts for the types of investments held by our plan.

The following chart reflects the assumptions used each year for the pension discount rate (exclusive of the SERP), the expected long-term return on plan assets and the actual return on plan assets and their impacts to the pension plan associated with the change in assumption (dollars in millions):

	2025	2024	2023
Discount rate (exclusive of SERP)			
Pension discount rate	5.96%	6.13%	5.86%
Increase/(decrease) to projected benefit obligation	$ 11	$ (17)	$ 14
Return on plan assets [(a)]			
Expected long-term return on plan assets	7.40%	7.80%	8.30%
Increase/(decrease) to pension costs	$ 2	$ 3	$ (13)
Actual return on plan assets, net of fees	13.20%	7.30%	15.00%
Actual gain (loss) on plan assets	$ 80	$ 42	$ 79

(a) The SERP has no plan assets. The plan assets in this disclosure are for the pension plan only.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage (dollars in millions):

Actuarial Assumption	Change in Assumption	Effect on Projected Benefit Obligation	Effect on Pension Cost
Expected long-term return on plan assets	(0.5)%	$ — *	$ 3
Expected long-term return on plan assets	0.5%	— *	(3)
Discount rate	(0.5)%	33	3
Discount rate	0.5%	(30)	(3)

** Changes in the expected return on plan assets would not affect our projected benefit obligation.*

We provide certain health care and life insurance benefits for substantially all of our retired employees. We accrue the estimated cost of postretirement benefit obligations during the years that employees provide service.

LIQUIDITY AND CAPITAL RESOURCES

OVERALL LIQUIDITY

Avista Corp.'s consolidated operating cash flows are primarily derived from the operations of Avista Utilities. The primary source of operating cash flows for Avista Utilities is revenues from sales of electricity and natural gas. Significant uses of cash flows from Avista Utilities include the purchase of power, emissions allowances, fuel and natural gas, and payment of other operating expenses, taxes and interest, with any excess being available for other corporate uses such as capital expenditures and dividends.

We design operating and capital budgets to control operating costs and to direct capital expenditures to projects that support immediate and long-term strategies, particularly for our regulated utility operations. In addition to operating expenses, we have continuing commitments for capital expenditures for construction and improvement of utility facilities.

Our annual net cash flows from operating activities usually do not fully support the amount required for annual utility capital expenditures. As such, from time-to-time, we need to access capital markets to fund these needs as well as fund maturing debt. See further discussion at "Capital Resources."

We regularly file for rate adjustments for recovery of operating costs and capital investments and to seek the opportunity to earn reasonable returns.

We have regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, when power and natural gas costs exceed the levels currently recovered from customers, net cash flows are negatively affected. Factors that could cause purchased power and natural gas costs to exceed the levels currently recovered from customers under base rates include, but are not limited to, higher prices in wholesale markets and/or an increased need to purchase power in the wholesale markets, and a lack of regulatory approval for higher authorized net power supply costs. Factors beyond our control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to:

- reduced snowpack and/or lower streamflows for hydroelectric generation (due to lower precipitation and/or warmer weather or extreme cold weather),
- increases in demand (due to either weather or customer growth),
- unplanned outages at generating facilities, and
- failure of third parties to deliver on energy or capacity contracts.

In addition to the above, we enter into derivative instruments to hedge exposure to certain risks, including fluctuations in commodity prices and foreign exchange rates (for purposes of issuing long-term debt in the future). These derivative instruments periodically require the posting of collateral (in the form of cash or letters of credit) or other credit enhancements or to reduce or terminate a portion of the contract through cash settlement, in the event of a downgrade in our credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against our cash on hand and credit facilities. See "Enterprise Risk Management—Credit Risk Liquidity Considerations" below.

Material contractual obligations that demand cash arise in the normal course of business including energy purchase contracts and contractual obligations related to generation facilities and transmission and distributions services. See "Note 14 of the Notes to Consolidated Financial Statements" for additional information related to these contractual obligations.

Additional demands for cash include payments of borrowings and interest payments (see "Notes 15-17 of the Notes to Consolidated Financial Statements"), lease obligations (see "Note 5 of the Notes to Consolidated Financial Statements"), pension and other postretirement benefit plan contributions (see "Note 12 of the Notes to Consolidated Financial Statements") and investment fund commitments (see "Note 6 of the Notes to Consolidated Financial Statements").

See discussion in "Capital Resources" below for available liquidity under our credit facilities. With our available liquidity under these agreements, we believe that we have adequate liquidity to meet our needs for the next 12 months.

REVIEW OF CONSOLIDATED CASH FLOW STATEMENT

2025 compared to 2024

Consolidated Operating Activities

Net cash provided by operating activities was $469 million for 2025 compared to $534 million for 2024. The decrease in net cash provided by operating activities primarily relates to a $158 million decrease in net power and natural gas cost deferrals and amortizations compared to 2024, primarily due to increased deferred power supply costs, as well as decreased amortizations associated with our PGAs. This decrease was partially offset by a $61 million increase associated with net amortizations and deferrals of other regulatory assets and liabilities, including increased CCA amortizations as costs were recovered from customers.

Consolidated Investing Activities

Net cash used in investing activities was $564 million for 2025, an increase compared to $539 million for 2024. During 2025, we paid $570 million for utility capital expenditures, compared to $533 million for 2024.

Consolidated Financing Activities

Net cash provided by financing activities was $84 million for 2025 compared to $0 million for 2024. The increase in financing cash flows was primarily the result of a $140 million of long-term debt issuances in 2025, compared to $84 million issued in 2024, and $78 million of common stock issued in 2025 compared to $68 million in 2024. We also increased our short-term borrowings by $33 million in 2025, compared to $5 million in 2024.

CAPITAL RESOURCES

Capital Structure

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings consisted of the following as of December 31, 2025 and 2024 (dollars in millions):

	December 31, 2025		December 31, 2024	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and leases	$ 9	0.1%	$ 8	0.1%
Short-term borrowings	388	6.5%	354	6.2%
Long-term debt to affiliated trusts	52	0.9%	52	0.9%
Long-term debt and leases	2,846	47.4%	2,711	47.4%
Total debt	3,295	54.9%	3,125	54.7%
Total Avista Corporation shareholders' equity	2,709	45.1%	2,591	45.3%
Total	$ 6,004	100.0%	$ 5,716	100.0%

Our shareholders' equity increased $118 million during 2025 primarily due to net income and the issuance of common stock, partially offset by dividends paid.

We need to finance capital expenditures and acquire additional funds for operations from time-to-time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduce the amount of cash available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements.

Short-Term Borrowings

Avista Corp.

Avista Corp. has a committed line of credit in the total amount of $500 million and an expiration date of June 2029, with the option to extend for an additional one-year period (subject to customary conditions). Avista Corp. also has a continuing letter of credit agreement in the aggregate amount of $50 million, and either party may terminate the agreement at any time.

The following table summarizes the balances outstanding and available liquidity as of December 31, 2025 (dollars in millions):

	Aggregate Amount	Amount Outstanding	Letters of Credit Outstanding [1]	Available Liquidity
Line of credit expiring June 2029	$ 500	$ 385	$ 5	$ 110
Letter of credit facility	50	N/A	14	36
Total	$ 550	$ 385	$ 19	$ 146

(1) Letters of credit are not reflected on the Consolidated Balance Sheets. If a letter of credit were drawn upon by the holder, we would have an immediate obligation to reimburse the bank that issued that letter.

The Avista Corp. credit facilities contain customary covenants and default provisions, including a change in control (as defined in the agreements). The events of default under each of the credit facilities also include a cross default from other indebtedness (as defined) and in some cases other obligations. The committed line of credit also includes a covenant which does not permit our ratio of "consolidated total debt"to "consolidated total capitalization" to be greater than 65 percent at any time. As of December 31, 2025, we complied with this covenant with a ratio of 54.9 percent.

Balances outstanding and interest rates on borrowings (excluding letters of credit) under Avista Corp.'s lines of credit were as follows as of and for the year ended December 31 (dollars in millions):

	2025	2024
$500 million line of credit, expiring June 2029		
Maximum balance outstanding during the year	$ 400	$ 350
Average balance outstanding during the year	298	270
Average interest rate during the year	5.35%	6.26%
Average interest rate at end of year	4.84%	5.52%

AEL&P

AEL&P has a $25 million committed line of credit with an expiration date in June 2028. As of December 31, 2025, there was $3 million outstanding at an average interest rate of 5.33 percent, and $22 million of available liquidity under this line of credit.

The AEL&P credit facility contains customary covenants and default provisions including a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of December 31, 2025, AEL&P complied with this covenant with a ratio of 50.0 percent.

As of December 31, 2025, Avista Corp. and its subsidiaries complied with the covenants of their financing agreements, and none of Avista Corp.'s subsidiaries constituted a "significant subsidiary" as defined in Avista Corp.'s committed line of credit.

Long-Term Debt

In July 2025, the Company issued and sold $120 million of 6.18 percent first mortgage bonds due in 2055 with institutional investors in the private placement market.

The net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under the Company's committed line of credit.

In July 2025, AEL&P entered into a term loan agreement in the amount of $20 million with an interest rate of 5.49 percent and a maturity date of July 2030. AEL&P borrowed the entire $20 million available under the agreement, and used the net proceeds to repay borrowings outstanding under AEL&P's committed line of credit, as well as fund capital expenditures.

Common Stock

We issued common stock in 2025 for total net proceeds of $78 million. Most of the stock was issued through our sales agency agreements under which we may offer and sell new shares of our common stock from time-to-time through our sales agents, with the balance related to compensation plans. In 2025, 2.0 million shares were issued under these agreements and plans.

2026 Liquidity Expectations

During 2026, we expect to issue up to $230 million of long-term debt and up to $90 million of common stock to fund planned capital expenditures.

After considering the expected issuances of long-term debt and common stock during 2026, we expect net cash flows from operating activities, together with cash available under our credit facilities, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Limitations on Issuances of Preferred Stock and First Mortgage Bonds

We are restricted under our Restated Articles of Incorporation, as amended, as to the additional preferred stock we can issue. As of December 31, 2025, we could issue $2.0 billion of preferred stock at an assumed dividend rate of 6.50 percent. We are not planning to issue preferred stock.

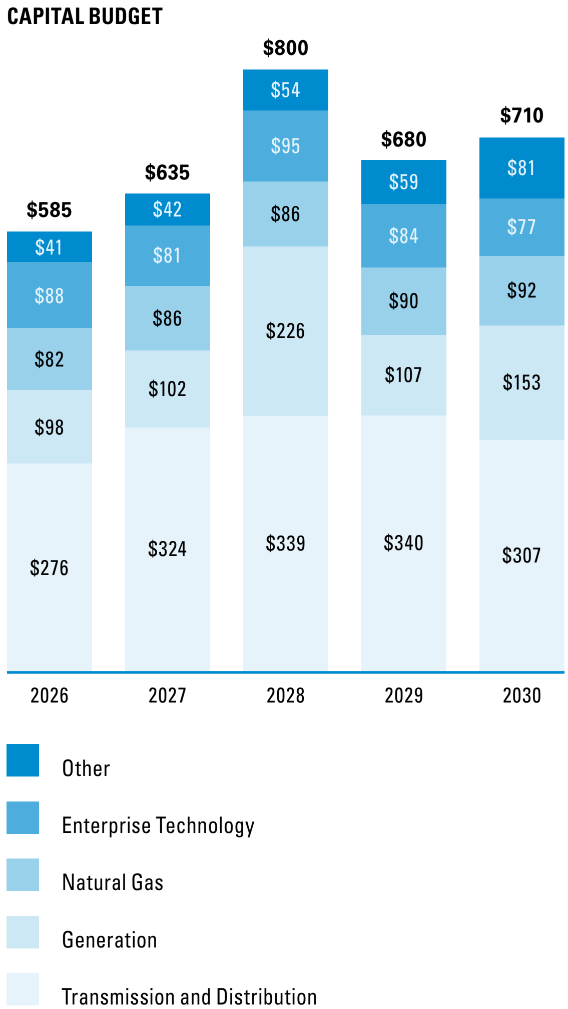
See "Note 16 of the Notes to Consolidated Financial Statements" for discussion of first mortgage bonds issuance limits.

UTILITY CAPITAL EXPENDITURES

Avista Utilities

We make capital investments to enhance service and system reliability for customers, replace aging infrastructure and serve increased demand. Actual capital expenditures for Avista Utilities for the year ended December 31, 2025 was $553 million.

The following graph shows Avista Utilities' expected capital expenditures for 2026-2030 by category (in millions):



These estimates include expenditures for the new projects listed within "Item 7. Management's Discussion and Analysis—Executive Overview—2025 Request for Proposal (RFP)." However, these estimates do not include potential expenditures that could result from integrating a new large load customer, incremental transmission projects like regional grid expansion, or additional generation.

AEL&P

The following table summarizes our actual and expected capital expenditures as of and for the year ended December 31, 2025 (dollars in millions):

2025 Actual capital expenditures		
Capital expenditures	$	17
Expected future annual capital expenditures (by year)		
2026	$	17
2027		16
2028		11

Avista Utilities and AEL&P's estimates of capital expenditures are subject to continuing review and adjustment. Actual expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

NON-REGULATED INVESTMENTS

We make investments at our other businesses including those related to economic development projects in our service territory that demonstrate the latest energy and environmental building innovations and house several local college degree programs. In addition, we make investments in emerging technology companies, venture capital funds, and other business ventures.

The following table summarizes our actual and expected investments at our other businesses as of and for the year ended December 31, 2025 (dollars in millions):

2025 Actual investments		
Investment expenditures	$	4
Expected future annual investments (by year)		
2026	$	7
2027		6
2028		6

These estimates of investments are subject to continuing review and adjustment. Actual expenditures may vary from our estimates due to factors such as changes in business conditions or strategic plans.

See "Liquidity" for information regarding other material cash requirements for 2026 and thereafter.

PENSION PLAN

We contributed $10 million to the pension plan in 2025. We expect to contribute a total of $50 million to the pension plan in the period 2026 through 2030, with an annual contribution of $10 million.

The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including changes to the fair value of pension plan assets, changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation), or changes in federal legislation. We may change our pension plan contributions in the future depending on changes to any variables, including those listed above.

See "Note 12 of the Notes to Consolidated Financial Statements" for additional information regarding the pension plan.

CREDIT RATINGS

Our access to capital markets and our cost of capital are directly affected by our credit ratings. In addition, many of our contracts for the purchase and sale of energy commodities contain terms dependent upon our credit ratings. See "Enterprise Risk Management—Credit Risk Liquidity Considerations" and "Note 8 of the Notes to Consolidated Financial Statements."

The following table summarizes our credit ratings as of February 24, 2026:

	Standard & Poor's (1)	Moody's (2)
Corporate/Issuer rating	BBB	Baa2
Senior Secured Debt	A-	A3
Senior Unsecured Debt	BBB	Baa2

(1) Standard & Poor's lowest "investment grade" credit rating is BBB-.

(2) Moody's lowest "investment grade" credit rating is Baa3.

A security rating is not a recommendation to buy, sell or hold securities. Each security rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered in the context of the applicable methodology, independent of all other ratings. The rating agencies provide ratings at the request of Avista Corp. and charge fees for their services.

DIVIDENDS

See "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for a detailed discussion of our dividend policy and the factors which could limit the payment of dividends.

COMPETITION

Our electric and natural gas distribution utility business has historically been recognized as a natural monopoly. In each regulatory jurisdiction, our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a "cost of service" basis. In theory, rates are designed to provide, after recovery of allowable operating expenses and capital investments, an opportunity to earn a reasonable return on investment as allowed by our regulators.

In retail markets, we compete with various rural electric cooperatives and public utility districts in and adjacent to our service territories in the provision of service to new electric customers. We have service territory agreements with certain rural electric cooperatives and public utility districts, approved in applicable jurisdictions, to set forth conditions under which one or the other utility will provide service to customers. Alternative energy technologies, including customer-sited solar, wind or geothermal generation, and energy storage, may also compete for sales to existing customers. Advances in power generation, energy efficiency, energy storage and other alternative energy technologies could lead to more wide-spread usage of these technologies, thereby reducing customer demand for the energy supplied by us. This reduction in usage and demand would reduce our revenue and negatively impact our financial condition, possibly leading to our inability to fully recover our investments in generation, transmission and distribution assets. Similarly, our natural gas distribution operations compete with other energy sources including heating oil, propane and other fuels.

Certain natural gas customers could bypass our natural gas system, reducing both revenues and recovery of fixed costs. To reduce the potential for such bypass, we price natural gas services, including transportation contracts, competitively and have varying degrees of flexibility to price transportation and delivery rates by means of individual contracts. These individual contracts are subject to regulatory review and approval. We have long-term transportation contracts with several of our largest industrial customers under which the customer acquires its own commodity while using our infrastructure for delivery. Such contracts reduce the risk of these customers bypassing our system in the foreseeable future and minimizes the impact on our earnings.

Customers may have a choice in the future over the sources from which to receive their energy. To effectively compete for our customers in the future, we continue to strive to create value through product and service offerings. We are also attempting to enhance the effectiveness and ease of our customer interactions by tailoring internal initiatives to focus on choices for customers to increase their overall satisfaction with the Company.

Also, non-utility businesses are developing new technologies and services to help energy consumers manage energy in new ways that may improve productivity and could alter demand for the energy we sell.

In wholesale markets, competition for available electric supply is influenced by the:

- localized and system-wide demand for energy,
- type, capacity, location and availability of generation resources, and
- variety and circumstances of market participants.

These wholesale markets are regulated by the FERC, which requires electric utilities to transmit power and energy to or for wholesale purchasers and sellers, enlarge or construct additional transmission capacity for the purpose of providing these services, and transparently price and offer transmission services without favor to any party, including the merchant functions of the utility.

Participants in the wholesale energy markets include:

- other utilities,
- federal power marketing agencies,
- energy marketing and trading companies,
- independent power producers,
- financial institutions, and
- commodity brokers.

ENVIRONMENTAL ISSUES AND CONTINGENCIES

We are subject to environmental regulation by federal, state, tribal and local authorities. The generation, transmission, distribution, service and storage facilities in which we have ownership interests or which we may need to acquire or develop are subject to environmental laws, regulations and rules relating to construction permitting, air quality and emissions, water quality, fisheries, wildlife, endangered species, avian interactions, wastewater and stormwater discharges, waste handling, natural resource protection, historic and cultural resource protection, and other similar activities. These laws and regulations require the Company to make substantial investments in compliance activities and to acquire and comply with a wide variety of environmental licenses, permits, approvals and settlement agreements. These items are enforceable by public officials and private individuals. Some of these regulations are subject to ongoing interpretation, whether administratively or judicially, and are often in the process of being modified. We conduct periodic reviews and audits of pertinent facilities and operations to enhance compliance and to respond to or anticipate emerging environmental issues. The Company's Board of Directors has established a committee to oversee environmental issues and to assess and manage environmental risk.

We monitor legislative and regulatory developments at different levels of government for environmental issues, particularly those with the potential to impact the operation of our generating plants and other assets, and our ability to provide service to natural gas customers. We continue to be subject to increasingly stringent or expanded application of environmental and related regulations from all levels of government.

Environmental laws and regulations may restrict or impact our business activities in many ways, including, but not limited to:

- increasing the operating costs of generating plants, natural gas and electric transmission and distribution facilities and other assets,
- increasing the lead time and capital costs for the construction of new generating plants, natural gas and electric transmission and distribution facilities and other assets,
- requiring modification of existing generating plants, natural gas and electric transmission and distribution facilities,
- requiring existing generating plant, natural gas and/or operations to be curtailed or shut down,
- reducing the amount of energy available from generating plants,
- restricting the types of generating plants that can be built or contracted with,
- requiring construction of specific types of generation plants at higher cost, and
- increasing costs of distributing, or limiting our ability to distribute, electricity and/or natural gas.

Compliance with environmental laws and regulations could result in increases to capital expenditures and operating expenses. We intend to seek recovery of such costs through the ratemaking process.

Policies and Other Impacts Related to Climate Change

Legal and policy changes responding to concerns about climate changes, and the potential impacts of such changes, could have a significant effect on our business. Direct impacts of climate changes include, without limitation, variations in the amount and timing of energy demand throughout the year, variations in the level and timing of precipitation throughout the year, as well as variations in temperature, and the resulting impact on the availability of hydroelectric resources at times of peak demand as well as an increased risk of wildfire and other impacts of extreme weather. Indirect impacts include, without limitation, changes in laws and regulations intended to mitigate the risk of, or alter, climate changes, including restrictions on the operation of our power generation resources and obligations or limitations imposed on the sale of natural gas. When direct or indirect impacts of climate change cause increased operational costs or capital investments, we intend to recover such costs through the ratemaking process.

Washington Legislation and Regulatory Actions

Clean Energy Transformation Act

In 2019, the Washington State Legislature passed the CETA, which effectively prohibits sales of energy produced by coal-fired generation to Washington retail customers after December 31, 2025 (with some exceptions for coal generated short-term purchases). In addition, the CETA establishes the policy of Washington State that retail sales of electricity to Washington customers must be carbon-neutral by January 1, 2030, however a utility may satisfy up to 20 percent of this requirement with specified emitting resources paired with either renewable offsets, credits and/or investments in qualifying energy transformation projects. By December 2044, 100 percent of retail sales of electricity to Washington State customers must be carbon free.

The law had direct, specific impacts on Colstrip, which were unique to the former owners of Colstrip who serve Washington customers. See "Colstrip" section and "Note 22 of the Notes to Consolidated Financial Statements" for further details on the impacts of the CETA on Colstrip and the transfer of our ownership interest in Colstrip to NorthWestern. Our hydroelectric and biomass generation facilities can be used to comply with the CETA's clean energy standards. We intend to seek recovery of costs associated with the clean energy legislation and regulations through the regulatory process.

In compliance with the CETA, we filed our first CEIP in October 2021, that was approved by the WUTC in June 2022. The CEIP's four-year compliance period of 2022-2025 proposed targets and specific actions to meet Washington State's clean energy goals and the equitable distribution of benefits and reduction of burdens to all customers. We have delivered on our commitments under the 2022–2025 CEIP.

In October 2025, the Company filed its 2025 CEIP with the WUTC in compliance with the Clean Energy Transformation Act. The CEIP proposed targets and specific actions to meet Washington State's clean energy goals and the equitable distribution of benefits and reduction of burdens to all customers.

Some highlights of the 2025 CEIP include:

- Updated clean energy targets: We propose increasing the amount of clean energy delivered to Washington customers from 66 percent in 2026 to 76.5 percent by 2029. The resulting projects from our 2025 RFP will contribute to reaching these targets.
- Modern energy management: Between 2026 and 2029, we plan to expand demand response programs that could reduce electricity usage by up to 55 MW during peaks. The electricity reductions include projects from the RFP process described above, and may include smart thermostats, battery storage, and other tools that help customers shift or lower their energy use when demand is highest.
- Energy efficiency programs: We will grow energy-saving programs to help customers use less electricity without giving up comfort or convenience.
- Community engagement: The CEIP emphasizes meaningful engagement with all communities, especially named communities, which are populations disproportionately affected by environmental, financial and societal factors, among others.

Emissions Performance Standard

Washington applies a GHG emissions performance standard to electric generation facilities used to serve retail loads, whether the facilities are located within Washington or elsewhere. The emissions performance standard prevents utilities from constructing or purchasing generation facilities, or entering into power purchase agreements of five years or longer duration to purchase energy produced by plants that have emission levels higher than 925 pounds of GHG per MWh. The Washington State Department of Commerce reviews the standard every five years. We intend to seek recovery of costs related to ongoing and new requirements through the ratemaking process.

Washington Climate Commitment Act

The CCA, and its implementing regulations, established a cap and trade program to reduce GHG emissions and achieve the GHG limits previously established under state law. The final rules implement a cap on emissions, provide mechanisms for the sale and tracking of tradable emissions allowances and establish additional compliance and accountability measures. The state issues allowances necessary to serve our Washington retail electric load; off-system wholesale sales may result in additional obligation costs. The CCA also has direct impacts on our Idaho electric operations as it applies to power that is delivered in Washington but is allocated to Idaho customers (wholesale sales) or power generated in Washington that is delivered to Idaho customers. Annually, the final calculated results must be certified by an independent third party and submitted to Ecology for approval. If the independent third party or Ecology disagrees with the approach or any of the calculations, it could result in a change to the number of allowances needed for compliance and could result in changes to anticipated costs for our electric operations. For Washington electric, we are allowed to defer any incremental costs associated with the CCA in accordance with our regulatory accounting order; however, in Idaho we are not allowed to recover any costs associated with CCA compliance from customers.

For our Washington natural gas operations, we have additional financial burdens associated with compliance which are being deferred and recovered from customers in accordance with our regulatory accounting order in Washington.

Washington State Building Codes

In April 2022, the Washington State Building Code Council (SBCC) approved a revised energy code requiring most new commercial buildings and large multifamily buildings to install all-electric space heating. An amendment to the code allows for natural gas to supplement electric heat pumps. In addition, in November 2022, the SBCC approved new building and energy codes for residential housing, requiring new residential buildings in Washington to use electricity as the primary heat source.

Both the commercial and residential building and energy codes were the subject of legal challenges in both Washington State Superior Court (the State Action) and in the Federal District Court for the Eastern District of Washington (the Federal Action). In the Federal Action, to which the Company was a party, the plaintiffs challenged the amendments on the grounds that they were preempted by the federal Energy Policy and Conservation Act (EPCA), citing the Ninth Circuit's decision in California Restaurant Association v. Berkeley (the Berkeley Decision), which involved similar restrictions on the use of natural gas in new construction in Berkeley, California.

In May 2023, the SBCC voted to delay the effective date of the code amendments and commenced an emergency rulemaking process to evaluate additional amendments to the code in light of the Berkeley Decision. As a result of this action, in July 2023, the Federal District Court declined to issue a preliminary injunction to prevent the amendments from taking effect. The plaintiffs in the Federal Action subsequently dismissed the action, without prejudice to their ability to refile after the SBCC rulemaking process is complete.

The SBCC has since voted to approve revised residential and commercial energy regulations that continue to require new residential and commercial buildings in Washington to use electricity as the primary heat source. In light of this action, the plaintiffs in the State Action amended their complaint to challenge the new regulations. The State Action remains pending.

In May 2024, we, along with Cascade Natural Gas Corporation, Northwest Natural Gas Company, and a coalition of homebuilders, heating unit dealers and other parties, filed a lawsuit challenging the approved building codes on the grounds that they are preempted by EPCA. The lawsuit was filed in the United States District Court for the Western District of Washington. This lawsuit remains pending.

In November 2024, Washington voters approved Initiative 2066, which would prohibit state and local governments from restricting access to natural gas, prohibit the SBCC from discouraging or penalizing the use of natural gas, and prohibit the WUTC from approving any multi-year rate plan that requires or incentivizes natural gas companies to terminate or limit natural gas service. In March 2025, a Washington state court held that the initiative violates the "single subject rule" and is invalid. That decision has been appealed and the appeal remains pending.

Over time, the building code changes would likely have an adverse impact on our natural gas business and natural gas customers but could also have a positive effect on our electric business. While we are in the process of studying the implications of the changes on our business, at this time we are not able to quantify the likely net effect, positive or negative, on our overall results of operations over the long term. However, the changes would clearly require that additional generating capacity be available to utilities and customers in Washington state.

Oregon Legislation and Regulatory Actions

Climate Protection Plan

In March 2020, Oregon Governor Kate Brown issued Executive Order No. 20-04, "Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions." The Executive Order launched rulemaking proceedings for every Oregon agency with jurisdiction over GHG-related matters, with the aim of reducing Oregon's overall GHG emissions to 80 percent below 1990 levels by 2050. This Executive Order led to the Oregon Department of Environmental Quality developing cap and reduce rules known as the CPP. The CPP, which became effective in January 2022, outlines GHG emissions reduction goals of 50 percent by 2035 and 90 percent by 2050 from the 1990 baseline. The first three-year compliance period was 2022 through 2024.

In March 2022, we, along with the utilities NW Natural and Cascade Natural Gas, filed a lawsuit requesting judicial review of the CPP. This action was subsequently consolidated with a lawsuit filed by several other parties. In December 2023, the Oregon Court of Appeals issued a decision declaring the CPP regulations invalid. The Oregon Department of Environmental Quality did not appeal the decision, but instead went back through the rulemaking process. The result of that process was a new version of the CPP that is very similar to the original. We are reviewing the new rules, and considering what legal action, if any, may be taken. To the extent the new rules impose additional compliance costs, we will seek to recover those costs through the ratemaking process.

Emissions Performance Standard

Oregon applies a GHG emissions performance standard to electric generation facilities, requiring that new baseload natural gas plant, non-base load natural gas plant, and non-generating facility reduce its net carbon dioxide emissions 17 percent below what the Oregon Facility Siting Council identifies as the most efficient combustion-turbine plant in the United States. The Oregon Energy Facility Siting Council issues rules periodically to update the standard, as more efficient power plants are built. The standard can be met by combination of efficiency, cogeneration, and offsets from carbon dioxide mitigation measures. We have thermal generation located in Oregon, and as such this standard applies to that facility. We intend to seek recovery of costs related to requirements through the ratemaking process.

Clean Air Act (CAA)

The CAA creates numerous requirements for our thermal generating plants. Kettle Falls GS, Coyote Springs and Rathdrum CT all require CAA Title V operating permits. The Boulder Park GS, Northeast CT and other operations require minor source permits or simple source registration permits. We have secured these permits and certify our compliance with Title V permits on an annual basis. These requirements can change over time as the CAA or applicable implementing regulations are amended and new permits are issued. We actively monitor legislative, regulatory and other program developments of the CAA that may impact our facilities.

2024 EPA Regulations for Power Plants

On April 25, 2024, the EPA released a package of final regulations addressed to electric generation facilities. These include:

- *Greenhouse gas regulations for new natural gas-based turbines and existing coal-based units, pursuant to section 111 of the Clean Air Act.* This rule finalizes (a) the repeal of the Affordable Clean Energy rule; (b) guidelines for GHG emissions from existing fossil fuel-fired steam generating electric generating units; and (c) revisions to existing performance standards for new, reconstructed or heavily modified fossil fuel-fired stationary combustion turbine electric generating units. The rule is currently being challenged in the D.C. circuit, and that litigation remains pending.
- *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule).* The ELG Rule applies to wastewater discharges from coal-based generating units and establishes pollution control requirements. The Rule builds upon the 2015 and 2020 ELG Rules. It includes a subcategory of requirements for coal plants that will be retired or repowered by the end of 2028 and provides additional compliance pathways for coal plants that retire by the end of 2034. The EPA is currently in the process of reconsidering the rule and compliance deadlines have been extended for certain provisions to allow for further evaluation.
- *Updated Mercury and Air Toxics Standards, pursuant to section 112 of the Clean Air Act (MATS Rule).* The MATS Rule sets emissions limits for filterable particulate matter for coal-based generating units. The Rule reduces those limits from the standards that were originally set in 2012. The EPA has since proposed repealing the reduction in applicable limits and has granted extensions of applicable compliance deadlines for certain power plants, including Colstrip.
- *Disposal of Coal Combustion Residuals from Electric Utilities—Legacy CCR Surface Impoundments (CCR Rule).* The CCR Rule builds on 2015 regulations, which apply to active power plants that dispose of coal combustion residuals in surface impoundments or landfills, by regulating inactive surface impoundments at inactive power plants and CCR management units at active and inactive power plants. In January 2025, the EPA issued a revised proposed and final rule to address language inconsistencies and submittal deadlines. Likewise, in February 2026, the EPA issued a final rule providing additional time for certain compliance deadlines regarding monitoring. Along with the other owners (including the operator), we have assessed the CCR Rule and believe there will not be a material change to our asset retirement obligation for Colstrip. See Coal Ash Management/Disposal, below for further discussion of the CCR Rule as it relates to Colstrip.

These rules potentially fall within the scope of a number of Presidential executive orders that have been issued, which are discussed in more detail under "2025 Presidential Executive Action" below. In addition, a substantial number of legal challenges have been filed regarding these rules, and those lawsuits remain pending. Finally, it is likely that the decision by the EPA to revoke its 2009 Endangerment Finding, discussed below, will have an impact on the status and implementation of these rules. At the same time, we continue to analyze each of these rules to assess the impact, if any, they may have on our existing generation units. To the extent there are any additional costs associated with compliance, we will seek to recover those costs through the ratemaking process.

EPA Endangerment Finding Revocation

In February 2026, the EPA formally revoked its 2009 Endangerment Finding, which was a landmark determination that six key greenhouse gases, including carbon dioxide and methane, threaten the public health and welfare of current and future generations. The Endangerment Finding provided the scientific and legal foundation for federal regulation of those identified greenhouse gases, including regulation of the release of greenhouse gases from power plants and other significant emissions sources.

The action taken by the EPA to repeal the Endangerment Finding is expected to result in significant deregulation of greenhouse gas emissions, including regulation of natural gas and coal-fired power plants. It is reasonably likely that the EPA's decision will be the subject of future legal challenges, the outcome of which cannot be predicted. The precise extent of that deregulation, as well as any potential impact on the Company's operations, cannot be determined at this time.

2025 Presidential Executive Actions

Since taking office, the U.S. President's Administration has issued a multitude of Executive Orders directed towards national energy resources and development. These include actions to:

- pause the disbursement of funds appropriated through the Inflation Reduction Act of 2022 or the Infrastructure and Jobs Act;
- require agency review of regulations, programs and executive orders that might limit the development or use of domestic energy resources such as oil, natural gas, coal and nuclear;
- revoke the prior Administration's Executive Orders on climate policy;
- require agency review of regulations, programs and executive orders that limit consumer choice for vehicles and appliances;
- require review of the 2009 EPA endangerment finding for greenhouse gases under the Clean Air Act;
- direct the EPA to revise or eliminate the use of a social cost of carbon in federal decision-making;
- declare a national emergency to expedite the development of energy infrastructure;
- direct emergency action under section 202(c) of the Federal Power Act by streamlining and expediting the approval of orders allowing electric generation resources to operate at maximum capacity during times of anticipated grid failure;
- direct the United States Attorney General to identify and act against state and local laws that burden domestic energy production and may be unconstitutional, preempted by federal law, or otherwise unlawful, particularly those tied to climate change, carbon penalties or carbon cap and trade programs, and Environmental, Social and Governance policies;
- restrict tax credits, tighten requirements and eliminate subsidies for wind and solar projects; and
- require the incorporation of sunset provisions into regulations governing energy production.

Some of these Executive Orders are the subject of legal challenges and/or are the subject of federal court injunctions, either in whole or in part. We are assessing potential impacts, opportunities and risks that may arise from these and other executive actions that may be taken by the Administration. To the extent that any action taken by the Administration results in increased costs for our business, we will seek to recover those costs through the rate-making process.

Other

For other environmental issues and other contingencies see "Note 22 of the Notes to Consolidated Financial Statements."

COLSTRIP

Colstrip is a coal-fired generating plant in southeastern Montana that includes four units and is owned by separate entities. Initially, we had a 15 percent ownership interest in Units 3 & 4. Due to CETA in Washington, in January 2023 we entered into an agreement with NorthWestern under which we transferred our ownership of Colstrip, effective midnight on January 1, 2026. See "Note 22 of the Notes to Consolidated Financial Statements" for further discussion of the agreement.

Coal Ash Management/Disposal

In 2015, the EPA issued a final rule regarding coal combustion residuals (CCRs), also termed coal combustion byproducts or coal ash (Colstrip produces this byproduct). The CCR rule has been the subject of ongoing litigation. In August 2018, U.S. Court of Appeals for the D.C. Circuit struck down provisions of the rule. In December 2019, a proposed revision to the rule was published in the Federal Register to address the D.C. Circuit's decision. The rule includes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements along with existing state obligations expressed through the 2012 Administrative Order on Consent (AOC) with Montana Department of Environmental Quality (MDEQ). These requirements continue despite the 2018 federal court ruling.

The AOC requires MDEQ to review Remedy and Closure plans for all parts of the Colstrip plant through an ongoing public process. The AOC also requires the Colstrip owners to provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro rata share of various anticipated closure and remediation obligations. We are responsible for our share of two major areas: the Plant Site Area and the Effluent Holding Pond Area. Generally, the plans include the removal of boron, chloride, and sulfate from the groundwater, closure of the existing ash storage ponds, and installation of a new water treatment system to convert the facility to a dry ash storage. Our share of the posted surety bonds is $14 million. This amount is updated annually, with expected obligations decreasing over time as remediation activities are completed. The transfer of our interest in Colstrip to NorthWestern did not relieve us of these obligations.

Colstrip Arbitration, Litigation, and Other Contingencies

See "Note 22 of the Notes to Consolidated Financial Statements" for disputes, arbitration, litigations and other contingencies related to Colstrip. We intend to seek recovery of costs associated with Colstrip through the ratemaking process.

ENTERPRISE RISK MANAGEMENT

The following discussion focuses on our processes and procedures to identify and manage the principal known risks that we face. See "Item 1A—Risk Factors," "Item 1C—Cybersecurity," "Forward-Looking Statements," as well as "Environmental Issues and Contingencies."

We consider the management of these risks an integral part of managing our core businesses and a key element of our approach to corporate governance.

Risk management includes identifying and measuring various forms of risk that may affect the Company. We have an enterprise risk management process for managing risks throughout the organization. Our Board of Directors and its Committees take an active role in the oversight of risk affecting the Company. We collect risk information across the Company, and senior management reviews the Company's major risks and risk mitigation measures. Each area identifies risks and implements the related mitigation measures. The enterprise risk process supports management in identifying, assessing, quantifying, managing and mitigating the risks. Despite all risk mitigation measures, however, risks are not eliminated.

Our primary identified categories of risk exposure are:

- Utility regulatory
- External mandates
- Operational
- Financial
- Climate change
- Energy commodity
- Cybersecurity
- Compliance
- Technology
- Resource adequacy
- Strategic

Our primary categories of risks are described in "Item 1A. Risk Factors."

Utility Regulatory Risk

We have a regulatory group which seeks to mitigate regulatory risk through open communications with regulatory commissioners and staff regarding the Company's business plans and concerns. The regulatory group also considers the regulator's priorities and rate policies and makes recommendations to senior management on regulatory strategy for the Company. Oversight of our regulatory strategies and policies is performed by senior management and the Board of Directors. See "Regulatory Matters" for further discussion of regulatory matters affecting the Company.

Operational Risk

To manage operational and event risks, we maintain emergency operating plans, business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and seek to negotiate indemnification arrangements with contractors for certain event risks. In addition, we design and follow detailed vegetation management and asset management inspection plans, which help mitigate wildfire and storm event risks, as well as identify utility assets which may be failing and in need of repair or replacement. We also have an Emergency Operating Center, which is a team of employees that plan for and train to deal with potential emergencies or unplanned outages at our facilities, resulting from natural disasters or other events. To prevent unauthorized access to our facilities, we have both physical and cybersecurity in place.

To address the risk related to fuel cost, availability and delivery restraints, we have an energy resources risk policy, which includes a wholesale energy markets credit policy and control procedures to manage energy commodity price and credit risks. Development of the energy resources risk policy includes planning for sufficient capacity to meet our customer and wholesale energy delivery obligations. See further discussion of the energy resources risk policy below.

Oversight of the operational risk management process is performed by the Environmental, Technology and Operations Committee of the Board of Directors and from senior management with input from each operating department.

Climate Change Risk

Multiple departments work to mitigate risks related to climate change. Climate change adds uncertainty to existing risks that we have historically managed and mitigated. These efforts are reflected in electric and gas operations, investments in assets and asset reliability and resiliency across our operations.

Power Supply staff monitor items such as snowpack and broader precipitation conditions, patterns and modeled or predicted climate change. These and other assessments are incorporated into our IRP processes. Environmental Affairs, Governmental Affairs and other departments monitor policy and regulatory developments that may relate to climate change to engage these efforts constructively and prepare for compliance matters.

Our Wildfire Resiliency Plan was also developed to mitigate the increased wildfire risk associated with climate change. See "Item 1. Business—Wildfire Resiliency Plan" for further discussion of the program.

In addition, issues concerning climate-related risk and our clean energy goals are reviewed and regularly discussed by the Board of Directors. The Board's Environmental, Technology and Operations Committee regularly reviews and discusses environmental and climate related risks, and advises the full Board on critical or emerging risks and/or related policies. Likewise, the Audit Committee provides oversight of climate-related disclosures.

Cybersecurity Risk

See "Item 1C.—Cybersecurity" for discussion of Cybersecurity risk and processes for mitigation.

Technology Risk

Technology governance is led by senior management, and includes new technology strategy, risk planning and major project planning and approval. Oversight of technology risk is performed by the Board's Environmental, Technology and Operations Committee. We are dedicated to securing, maintaining and evaluating and developing our information technology systems. We evaluate our technology for obsolescence and upgrade or replace systems as necessary. The technology project management office and enterprise business performance team provide project cost, timeline and schedule oversight.

We manage Generative Artificial Intelligence (GenAI) risks through governance and policy to safeguard data and minimize operational risk. Governance and oversight is performed by a committee composed of senior management who oversee GenAI risks across cybersecurity, technology, and operational domains. This group strives to ensure alignment with our broader risk management framework, which includes approving tools, applying cross-functional risk assessments to proposed use cases, responsible use, data protection, and awareness of GenAI limitations, including risks of inaccurate or biased outputs. This committee and its members also provide updates on risk management activities and GenAI initiatives to Board Committees. Under this approach, GenAI adoption supports operational efficiency while minimizing legal, security, financial, and reputational risks.

Strategic Risk

Oversight of strategic risk is performed by the Board of Directors and senior management. We have a Senior Vice President, Energy Policy and Chief Strategy Officer who leads strategic initiatives, searches for and evaluates opportunities and makes recommendations to other members of senior management and the Board of Directors. We not only focus on whether opportunities are financially viable, but also consider whether these opportunities fall within our core policies and our core business strategies. We strive to mitigate reputational risk primarily through a focus on adherence to our core policies, including our Code of Conduct, maintaining an appropriate culture and tone at the top, and through communication and engagement with external stakeholders.

External Mandates Risk

Oversight of external mandate risk mitigation strategies is performed by the Environmental, Technology and Operations Committee of the Board of Directors and senior management. Our Environmental, Social and Governance program creates a framework that is intended to attract investment, enhancement of our brand, and promotion of sustainable long-term growth. We also have employees dedicated to actively engage and monitor federal, state and local government positions and legislative actions that may affect us or our customers.

To prevent the threat of municipalization, we work to build strong relationships with the communities we serve through, among other things:

- communicating and being involved with local business leaders and community organizations,
- providing customers with a multitude of limited income initiatives, including energy fairs, senior outreach, low income workshops, mobile outreach strategy and a Low Income Rate Assistance Plan,
- tailoring internal initiatives to focus on choices for customers, to increase their overall satisfaction with the Company, and
- engaging in the legislative process in a manner that fosters the interests of our customers and the communities we serve.

Financial Risk

Financial risk is impacted by many factors, including regulation and rates, weather risk, access to capital markets, interest rate risk, credit risk, and foreign exchange risk. Our Treasury department monitors our daily cash position and future cash flow needs, as well as monitoring market conditions to determine the appropriate course of action for capital financing strategies. Oversight of financial risk mitigation strategies is performed by senior management and the Finance Committee of the Board of Directors.

Regulation and Rates

The Regulatory Affairs department is critical in mitigation of financial risk as they have regular communications with state commission regulators and staff, and they monitor and develop rate strategies. Rate strategies, such as decoupling and operating expense balancing accounts, help mitigate the impacts of revenue fluctuations due to weather, conservation or the economy.

Weather Risk

To partially mitigate the risk of financial under-performance due to weather-related factors, we developed decoupling rate mechanisms that were approved by the Washington, Idaho and Oregon commissions. Decoupling mechanisms are designed to break the link between a utility's revenues and consumers' energy usage and instead provide revenue based on the number of customers, thus mitigating a large portion of the risk associated with lower customer loads. See "Note 23 of the Notes to Consolidated Financial Statements" for further discussion of our decoupling mechanisms.

Access to Capital Markets

Our capital requirements rely to a significant degree on regular access to capital markets. We actively engage with rating agencies, banks, investors and state public utility commissions to understand and address the factors that support access to capital markets on reasonable terms. We manage our capital structure to maintain a financial risk profile that we believe will be deemed prudent. We forecast cash requirements to determine liquidity needs, including sources and variability of cash flows that may arise from spending plans or from external forces, such as changes in energy prices or interest rates. Our financial and operating forecasts consider various metrics that affect credit ratings. Our regulatory strategies include working with state public utility commissions and filing for rate changes as appropriate to meet financial performance expectations.

Interest Rate Risk

Uncertainty about future interest rates causes risk related to a portion of existing debt, future borrowing requirements, and pension and other postretirement benefit obligations. We manage debt interest rate risk by limiting variable rate debt to a percentage of total capitalization, monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and establishing fixed rate long-term debt with varying maturities. We may hedge a portion of our interest rate risk with derivative instruments, particularly to manage risk associated with significant concentrations of forecasted debt issuances. The Finance Committee of the Board of Directors periodically reviews and discusses interest rate risk management processes, and the steps management has undertaken to control interest rate risk. Our Risk Management Committee (RMC) also reviews the interest rate risk management plan.

The interest rate on $52 million of long-term debt to affiliated trusts is adjusted quarterly, reflecting current market rates. Amounts borrowed under our committed line of credit agreements have variable interest rates.

The following table shows long-term debt and related weighted-average interest rates, by expected maturity dates as of December 31, 2025 (dollars in millions):

	2026	2027	2028	2029	2030	Thereafter	Total	Fair Value
Fixed rate long-term debt[1]	$ —	$ —	$ 25	$ 15	$ 20	$ 2,714	$ 2,774	$ 2,279
Weighted-average interest rate	—	—	6.37%	5.92%	5.49%	4.40%	4.43%	
Variable rate long-term debt to affiliated trusts	—	—	—	—	—	$ 52	$ 52	$ 46
Weighted-average interest rate	—	—	—	—	—	4.93%	4.93%	

(1) These balances include the fixed rate long-term debt of Avista Corp., AEL&P and AERC.

Our pension plan is exposed to interest rate risk because the value of pension obligations and other postretirement obligations varies directly with changes in the discount rates, which are derived from end-of-year market interest rates. In addition, the value of pension investments and potential income on pension investments is partially affected by interest rates because a portion of pension investments are in fixed income securities. Oversight of pension plan investment strategies is performed by the Finance Committee of the Board of Directors, which approves investment and funding policies, objectives and strategies that seek an appropriate return for the pension plan. We manage interest rate risk associated with pension and other postretirement benefit plans by investing a targeted amount of pension plan assets in fixed income investments that have maturities with similar profiles to future projected benefit obligations. See "Note 12 of the Notes to Consolidated Financial Statements" for further discussion of our investment policy associated with the pension plan assets.

Credit Risk

Counterparty Non-Performance Risk

We enter into bilateral transactions with various counterparties. We also trade energy and related derivative instruments through clearinghouses and exchanges.

Counterparty non-performance risk relates to potential losses that we would incur due to non-performance of contractual obligations by counterparties to deliver energy or make financial settlements.

Changes in market prices may dramatically alter the size of credit risk with counterparties, even when we establish conservative credit limits. Should a counterparty fail to perform, we may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices.

We seek to mitigate counterparty credit risk by:

- transacting through clearinghouses and exchanges,
- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring credit exposures,
- asserting collateral rights with counterparties, and
- carrying out transaction settlements timely and effectively.

The extent of transactions conducted through clearinghouses and exchanges has increased, as many market participants have shown a preference for trading through these entities and have reduced bilateral transactions. We actively monitor the collateral required by clearinghouses and exchanges to effectively manage capital requirements.

Our exposure to risks attributable to counterparties' credit profile is dynamic in normal markets and may change significantly in more volatile markets. The amount of potential default risk from each counterparty depends on the duration and volume of our obligations under forward contracts, unsettled transactions, interest rates and market prices, as well as other factors. There is a risk that we do not obtain sufficient additional collateral from counterparties that are unable or unwilling to provide it.

Credit Risk Liquidity Considerations

To address the impact on our operations of energy market price volatility, our hedging practices for electricity (including fuel for generation) and natural gas extend beyond the current operating year. Executing this extended hedging program may increase our credit risk and demands on us for collateral. Our credit risk management process is designed to mitigate such risks through limit setting, contract protections and counterparty diversification, among other practices.

Credit risk affects demands on our capital. We are subject to limits and credit terms that counterparties may assert to enter into transactions with them for them to maintain acceptable credit exposure to us. Many of our counterparties allow unsecured credit at limits prescribed by agreements or their discretion. Capital requirements for certain transaction types involve a combination of initial margin and market value margins without unsecured credit threshold. Counterparties may seek assurances of performance in the form of letters of credit, prepayment or cash deposits.

Credit exposure can change significantly in periods of commodity price and interest rate volatility. As a result, sudden and significant demands may be made against our credit facilities and cash. We actively monitor the exposure to possible collateral calls and take steps to minimize capital requirements.

As of December 31, 2025, we had deposited as collateral cash in the amount of $12 million and letters of credit in the amount of $14 million related to energy contracts. Price movements and/or a downgrade in our credit ratings or other established credit criteria could impact further the amount of collateral required. See "Credit Ratings" for further information.

For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below "investment grade" based on positions outstanding at December 31, 2025 (including contracts that meet the definition of a derivative under U.S. GAAP and those that are not accounted for as derivatives), we would potentially be required to post the following additional collateral (dollars in millions):

	December 31, 2025
Additional collateral taking into account contractual thresholds(1)	$ 27
Additional collateral without contractual thresholds	40

(1) This amount is different from the amount disclosed in "Note 8 of the Notes to Consolidated Financial Statements" because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 8, this analysis also takes into account contractual threshold limits that are not considered in Note 8.

Foreign Currency Risk

A significant portion of our utility natural gas supply (including fuel for electric generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices. The short-term natural gas transactions are typically settled within sixty days with U.S. dollars. We hedge a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. This risk has not had a material effect on our financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

Further information for derivatives and fair values is disclosed at "Note 8 of the Notes to Consolidated Financial Statements" and "Note 18 of the Notes to Consolidated Financial Statements."

Energy Commodity Risk

We mitigate energy commodity risk primarily through our energy resources risk policy, which includes oversight from the RMC and oversight from the Audit Committee and the Environmental, Technology and Operations Committee of the Board of Directors. In conjunction with the oversight committees, our management team develops hedging strategies, detailed resource procurement plans, resource optimization strategies and long-term integrated resource planning to mitigate some of the risks associated with energy commodities. The various plans and strategies are monitored daily and developed with quantitative methods.

Our energy resources risk policy includes a wholesale energy markets credit policy and control procedures to manage energy commodity price and credit risks. Nonetheless, adverse changes in commodity prices, generating capacity, customer loads, regulation, weather, and other factors may result in losses of earnings, cash flows and/or fair values.

We measure the volume of monthly, quarterly and annual energy imbalances between projected power loads and resources. The measurement process is based on expected loads at fixed prices (including those subject to retail rates) and expected resources to the extent costs are essentially fixed by virtue of known fuel supply costs or projected hydroelectric conditions. To the extent expected costs are not fixed, either because of volume mismatches between loads and resources or because fuel cost is not locked in through fixed price contracts or derivative instruments, our risk policy guides the process to manage this open forward position over a period of time. Normal operations result in seasonal mismatches between power loads and available resources. We vary the operation of generating resources to match parts of intra-hour, hourly, daily and weekly load fluctuations. We use the wholesale power markets, including the natural gas market as it relates to power generation fuel, to sell projected resource surpluses and obtain resources when deficits are projected. We buy and sell fuel for thermal generation facilities based on comparative power market prices and marginal costs of fueling and operating available generating facilities and the relative economics of substitute market purchases for generating plant operation.

To address the impact on our operations of energy market price volatility, our hedging practices for electricity (including fuel for generation) and natural gas extend beyond the current operating year. Executing this extended hedging program may increase credit risks. Our credit risk management process is designed to mitigate such credit risks through limit setting, contract protections and counterparty diversification, among other practices.

Projected retail natural gas loads and resources are regularly reviewed by operating management and the RMC. To manage the impacts of volatile natural gas prices, we procure natural gas through a diversified mix of spot market purchases and forward fixed price purchases from various supply basins and time periods. We have an active hedging program that extends into future years with the goal of reducing price volatility in natural gas supply costs. We use natural gas storage capacity to support high demand periods and to procure natural gas when price spreads are favorable. Securing prices throughout the year and even into subsequent years mitigates potential adverse impacts of significant purchase requirements in a volatile price environment.

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2025 that are expected to settle in each respective year (dollars in millions). As of December 31, 2025, there are no energy commodity derivative contracts outstanding with expected deliveries after 2028:

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2026	$ —	$ —	$ (17)	$ (10)	$ 8	$ 4	$ (3)	$ —
2027	—	—	(3)	(1)	—	—	(4)	—
2028	—	—	—	—	—	—	(3)	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2024 that were expected to settle in each respective year (dollars in millions). As of December 31, 2024, there were no energy commodity derivative contracts outstanding with expected deliveries after 2027:

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)	Physical (1)	Financial (1)
2025	$ —	$ —	$ (23)	$ (19)	$ 10	$ 7	$ (3)	$ —
2026	—	—	(9)	(3)	—	—	—	—
2027	—	—	(2)	—	—	—	—	—

(1) Physical transactions represent commodity transactions in which we take or make delivery of either electricity or natural gas; financial transactions represent financial derivative instruments that are settled in cash with no physical delivery of the underlying commodity, such as futures, swap derivatives, or options contracts.

The above electric and natural gas derivative contracts will be included in either power supply costs or natural gas supply costs during the period they are delivered and will be included in the various deferral and recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to eventually be collected through retail rates from customers.

See "Item 1. Business—Electric Operations" and "Item 1. Business—Natural Gas Operations," for additional discussion of the risks associated with Energy Commodities.

Compliance Risk

Compliance risk is mitigated through separate Regulatory and Environmental Compliance departments that monitor legislation, regulatory orders and actions to determine the overall potential impact and develop strategies for complying with the various rules and regulations. We also engage outside attorneys and consultants, when necessary, to help ensure compliance with laws and regulations. Oversight of compliance risk strategy is performed by senior management, including the Chief Compliance Officer, and the Environmental, Technology and Operations Committee and the Audit Committee of the Board of Directors.

See "Item 1. Business, Regulatory Issues" through "Item 1. Business, Reliability Standards" and "Environmental Issues and Contingencies" for further discussion of compliance issues that impact our Company.

Resource Adequacy Risk

Resource adequacy risk is managed internally through our integrated resource planning (IRP) evaluation that produces a preferred resource strategy to meet forecasted energy demand over the next twenty plus years. The IRP is conducted every two years to account for changes in assumptions such as forecasted load growth, energy market prices, climate change and other variables. If new resources are shown to be needed in the next four years, then we will initiate a competitive resource request for proposal process to procure new generating resources prior to the anticipated need. We will also hedge shorter term capacity and energy needs per our risk management policy to acquire additional generation as needed. We also participate in the Western EIM and the western resource adequacy program to reduce risk associated with near term energy and capacity needs.

External resource adequacy risk associated with regional capacity shortfalls is monitored and addressed through participation in regional coordination efforts. These efforts include participation in interregional transmission planning conducted by the western power pool, day ahead organized markets, western resource adequacy program, gas-electric coordination initiatives, joint regional transmission infrastructure projects and evaluation of joint generation projects.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is set forth in the Enterprise Risk Management section of "Item 7. Management's Discussion and Analysis" and is incorporated herein by reference.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Report of Independent Registered Public Accounting Firm and Financial Statements begin on the next page.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Avista Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2026, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Matters—Refer to Notes 1, 22, and 23 to the financial statements

Critical Audit Matter Description

The Company accounts for its regulated operations in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 980, Regulated Operations ("ASC 980"). The provisions of this accounting guidance require, among other things, that financial statements of a rate-regulated enterprise reflect the actions of regulators, where appropriate. These actions may result in the recognition of revenues and expenses in time periods that are different than non-rate-regulated enterprises. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses when those amounts are reflected in rates. Also, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future (regulatory liabilities).

The Company is subject to regulation by the Washington Utilities and Transportation Commission, the Idaho Public Utilities Commission, the Public Utility Commission of Oregon, the Public Service Commission of the State of Montana and the Regulatory Commission of Alaska (collectively, the "Commissions"), which have jurisdiction with respect to, among other things, the rates of electric and natural gas distribution companies in Washington, Idaho, Oregon, Montana, and Alaska, respectively. Accounting for the economics of rate regulation has an impact on certain financial statement line items and disclosures.

The Company's rates are subject to the rate-setting processes of the Commissions and, in certain jurisdictions, annual earnings oversight. Rates are determined and approved in regulatory proceedings based on analyses of the Company's costs to provide utility service and are designed to recover the Company's prudently incurred investments in the utility business and provide a return thereon. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations under ASC 980 as described above. While the Company has indicated that it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve (1) full recovery of the costs of providing utility service or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of part of the cost of recently completed plant or plant under construction and (3) refunds to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions included the following procedures, among others:

- We tested the effectiveness of management's controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred and deferred as regulatory assets and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities. We also tested the effectiveness of management's controls over the initial recognition of amounts as property, plant and equipment; regulatory assets or liabilities; and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- We evaluated the Company's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.
- We read relevant regulatory orders issued by the Commissions for the Company and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on the precedents of the Commissions' treatment of similar costs under similar circumstances. We evaluated the external information and compared it to management's recorded regulatory asset and liability balances for completeness.
- We inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors that may impact the Company's future rates, evaluating the evidence in relation to management's assertions, as applicable.
- We inquired of management about property, plant, and equipment that may be abandoned. We inspected the capital-projects budget and construction-work-in-process listings and inquired of management to identify projects that are designed to replace assets that may be retired prior to the end of their useful life. We inspected minutes of the Board of Directors and regulatory orders and other filings with the Commissions, evaluating the evidence in relation to management's assertions, as applicable, regarding probability of an abandonment.
- We obtained an analysis from management regarding probability of recovery for regulatory assets or probability of either refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order in order to assess management's assertion that amounts are probable of recovery and/or that a future refund or reduction in rates is not probable.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 24, 2026

We have served as the Company's auditor since 1933.

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Years Ended December 31

Dollars in millions, except per share amounts

	2025	2024	2023
Operating Revenues:			
Utility revenues:			
Utility revenues, exclusive of alternative revenue programs	$ 1,940	$ 1,902	$ 1,746
Alternative revenue programs	23	35	5
Total utility revenues	1,963	1,937	1,751
Non-utility revenues	1	1	1
Total operating revenues	1,964	1,938	1,752
Operating Expenses:			
Utility operating expenses:			
Resource costs	691	798	702
Other operating expenses	504	442	414
Depreciation and amortization	289	274	265
Taxes other than income taxes	121	116	110
Non-utility operating expenses	5	2	3
Total operating expenses	1,610	1,632	1,494
Income from operations	354	306	258
Interest expense	152	147	141
Interest expense to affiliated trusts	2	3	3
Capitalized interest	(6)	(5)	(4)
Other income—net	(11)	(22)	(19)
Income before income taxes	217	183	137
Income tax expense (benefit)	24	3	(34)
Net income	$ 193	$ 180	$ 171
Weighted-average common shares outstanding (thousands)—basic	80,975	78,725	76,396
Weighted-average common shares outstanding (thousands)—diluted	81,051	78,820	76,495
Earnings per common share:			
Basic	$ 2.38	$ 2.29	$ 2.24
Diluted	$ 2.38	$ 2.29	$ 2.24

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Years Ended December 31

Dollars in millions

	2025	2024	2023
Net income	$ 193	$ 180	$ 171
Other Comprehensive (Loss) Income:			
Change in unfunded benefit obligation for pension and other postretirement benefit plans—net of taxes of $0, $0 and $0, respectively	(1)	—	2
Total other comprehensive (loss) income	(1)	—	2
Comprehensive income	$ 192	$ 180	$ 173

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation
As of December 31
Dollars in millions

	2025	2024
Assets:		
Current Assets:		
Cash and cash equivalents	$ 19	$ 30
Accounts and notes receivable—net	220	205
Inventory	236	193
Regulatory assets	135	137
Other current assets	119	91
Total current assets	729	656
Net utility property	6,319	5,987
Goodwill	52	52
Non-current regulatory assets	871	847
Other property and investments—net and other non-current assets	388	399
Total assets	$ 8,359	$ 7,941
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 163	$ 125
Short-term borrowings	388	354
Regulatory liabilities	126	108
Other current liabilities	201	184
Total current liabilities	878	771
Long-term debt	2,754	2,614
Long-term debt to affiliated trusts	52	52
Pensions and other postretirement benefits	65	75
Deferred income taxes	778	751
Non-current regulatory liabilities	818	834
Other non-current liabilities and deferred credits	305	253
Total liabilities	5,650	5,350
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Equity:		
Common stock, no par value; 200,000 shares authorized; 82,193 and 80,039 shares issued and outstanding, respectively (shares in thousands)	1,805	1,720
Accumulated other comprehensive loss	(1)	—
Retained earnings	905	871
Total equity	2,709	2,591
Total liabilities and equity	$ 8,359	$ 7,941

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation
For the Years Ended December 31
Dollars in millions

	2025	2024	2023
Operating Activities:			
Net income	$ 193	$ 180	$ 171
Non-cash items included in net income:			
Depreciation and amortization	289	274	265
Benefit from (provision for) deferred income taxes	2	(5)	(37)
Power and natural gas cost (deferrals) amortizations—net	(54)	104	7
Amortization of debt expense	2	2	3
Stock-based compensation expense	9	9	8
Equity-related AFUDC	(11)	(9)	(7)
Pension and other postretirement benefit expense	15	12	14
Other regulatory assets and liabilities	33	(28)	(34)
Other non-current assets and liabilities	58	36	26
Change in decoupling regulatory deferral	(24)	(35)	(3)
Realized and unrealized losses on assets and investments	13	5	3
Other	(4)	(4)	(6)
Contributions to defined benefit pension plan	(10)	(10)	(10)
Cash received on settlement of interest rate swap agreements	1	4	8
Changes in certain current assets and liabilities:			
Accounts and notes receivable	(24)	3	37
Inventory	(43)	(40)	(52)
Collateral posted for derivative instruments	12	18	129
Income taxes receivable	(5)	(3)	2
Other current assets	(23)	16	(26)
Accounts payable	25	(8)	(66)
Other current liabilities	15	13	15
Net cash provided by operating activities	469	534	447
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(570)	(533)	(499)
Issuance of notes receivable	—	—	(3)
Repayments from notes receivable	6	—	—
Equity and property investments	(4)	(10)	(13)
Proceeds from sale of investments	—	—	3
Other	4	4	2
Net cash used in investing activities	$ (564)	$ (539)	$ (510)

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (CONTINUED)

Avista Corporation
For the Years Ended December 31
Dollars in millions

	2025	2024	2023
Financing Activities:			
Net increase (decrease) in short-term borrowings	$ 33	$ 5	$ (114)
Proceeds from issuance of long-term debt	140	84	250
Maturity of long-term debt and finance leases	(4)	(3)	(17)
Issuance of common stock—net of issuance costs	78	68	113
Cash dividends paid	(159)	(150)	(141)
Other	(4)	(4)	(6)
Net cash provided by financing activities	84	—	85
Net (decrease) increase in cash and cash equivalents	(11)	(5)	22
Cash and cash equivalents at beginning of year	30	35	13
Cash and cash equivalents at end of year	$ 19	$ 30	$ 35
Supplemental Cash Flow Information:			
Cash paid during the year for interest	$ 144	$ 141	$ 132
Non-cash financing and investing activities:			
Accounts payable for capital expenditures	36	24	34

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF EQUITY

Avista Corporation
For the Years Ended December 31
Dollars in millions, except per share amounts

	2025	2024	2023
Common Stock, Shares (in thousands):			
Shares outstanding at beginning of year	80,039	78,075	74,946
Shares issued through equity compensation plans	148	147	118
Shares issued through Employee Investment Plan	13	13	12
Shares issued through sales agency agreements	1,993	1,804	2,999
Shares outstanding at end of year	82,193	80,039	78,075
Common Stock, Amount:			
Balance at beginning of year	$ 1,720	$ 1,644	$ 1,525
Equity compensation expense	8	8	7
Issuance of common stock through equity compensation plans	1	1	1
Issuance of common stock through sales agency agreements—net of issuance costs	78	68	112
Payment of minimum tax withholdings for share-based payment awards	(2)	(1)	(1)
Balance at end of year	1,805	1,720	1,644
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	—	—	(2)
Other comprehensive (loss) income	(1)	—	2
Balance at end of year	(1)	—	—
Retained Earnings:			
Balance at beginning of year	871	841	812
Net income	193	180	171
Dividends on common stock	(159)	(150)	(142)
Balance at end of year	905	871	841
Total equity	$ 2,709	$ 2,591	$ 2,485
Dividends declared per common share	$ 1.96	$ 1.90	$ 1.84

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. is primarily an electric and natural gas utility with certain other business ventures. Avista Utilities is an operating division of Avista Corp., comprising its regulated utility operations in the Pacific Northwest. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana.

AERC is a wholly owned subsidiary of Avista Corp. The primary subsidiary of AERC is AEL&P, which comprises Avista Corp.'s regulated utility operations in Alaska.

Avista Capital, a wholly owned non-regulated subsidiary of Avista Corp., is the parent company of the subsidiary companies in the non-utility businesses, except AJT Mining Properties, Inc., which is a subsidiary of AERC. See Note 24 for business segment information.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances are eliminated in consolidation. The accompanying consolidated financial statements include the Company's proportionate share of utility plant and related operations associated with its interests in jointly owned plants (see Note 9).

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported for assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- obligations under the CCA,
- goodwill impairment testing,
- fair value of equity investments,
- recoverability of regulatory assets, and
- unbilled revenues.

Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on the consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein.

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana, Oregon and Alaska. The Company is subject to federal regulation primarily by the FERC, as well as various other federal agencies with regulatory oversight of particular aspects of its operations.

Depreciation

For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives.

For utility operations, the ratio of depreciation provisions to average depreciable property was as follows for the years ended December 31:

	2025	2024	2023
Avista Utilities	3.52%	3.45%	3.52%
Alaska Electric Light and Power Company	2.77%	2.80%	2.78%

The average service lives for the following broad categories of utility plant in service are (in years):

	Avista Utilities	Alaska Electric Light and Power Company
Electric thermal/other production	20	41
Hydroelectric production	80	40
Electric transmission	43	43
Electric distribution	41	38
Natural gas distribution property	43	N/A
Other shorter-lived general plant	8	19

Allowance for Funds Used During Construction

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant. The debt component of AFUDC is credited against total interest expense in the Consolidated Statements of Income in the line item "capitalized interest." The equity component of AFUDC is included in the Consolidated Statements of Income in the line item "other income—net." The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base.

The WUTC and IPUC have authorized Avista Utilities to calculate AFUDC using its allowed rate of return on rate base. To the extent amounts calculated using this rate exceed the AFUDC amounts calculated using the FERC formula, Avista Utilities capitalizes the excess as a regulatory asset. The regulatory asset associated with plant in service is amortized over the average useful life of Avista Utilities' utility plant which is approximately 30 years. The regulatory asset associated with construction work in progress is not amortized until the plant is placed in service.

The effective AFUDC rate was the following for the years ended December 31:

	2025	2024	2023
Avista Utilities	7.32%	7.03%	7.03%
Alaska Electric Light and Power Company	7.77%	8.47%	8.61%

Income Taxes

Deferred income tax assets represent future income tax deductions the Company expects to utilize in future tax returns to reduce taxable income. Deferred income tax liabilities represent future taxable income the Company expects to recognize in future tax returns. Deferred tax assets and liabilities arise when there are temporary differences resulting from differing treatment of items for tax and accounting purposes. A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the temporary differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company's consolidated income tax returns. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the date of the enactment unless a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time. The Company establishes a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Deferred income tax assets and liabilities and regulatory assets and liabilities are established for income tax benefits flowed through to customers.

The Company has elected to account for transferable tax credits as a component of the income tax provision. The Company recognizes the benefit of production tax credits as a reduction of income tax expense in the period the credit is generated, which corresponds to the period the energy production occurs. The Company applies the deferral method of accounting for investment tax credits (ITCs). Under this method, ITCs are amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

The Company's largest deferred income tax item is the difference between the book and tax basis of utility plant. This item results from the temporary difference in depreciation expense. In early tax years, this item is recorded as a deferred income tax liability that will eventually reverse and become subject to income tax in later tax years.

The Company did not incur penalties on income tax positions in 2025, 2024 or 2023. The Company would recognize interest accrued related to income tax positions as interest expense or interest income and penalties incurred as other operating expense.

Stock-Based Compensation

The Company issues three types of stock-based compensation awards—restricted shares, market-based awards and performance-based awards. Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity instruments issued and recorded over the requisite service period.

The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Consolidated Statements of Income of the following amounts for the years ended December 31 (dollars in millions):

	2025	2024	2023
Stock-based compensation expense	$ 8	$ 8	$ 7
Income tax benefits	2	2	2

Restricted share awards vest in equal thirds each year over 3 years and are payable in Avista Corp. common stock at the end of each year if the service condition is met. Restricted stock is valued at the close of market of the Company's common stock on the grant date.

Total Shareholder Return (TSR) awards are market-based awards and Cumulative Earnings Per Share (CEPS) awards are performance awards. Both types of awards vest after a period of 3 years and are payable in cash or Avista Corp. common stock at the end of the three-year period. The method of settlement is at the discretion of the Company and historically the Company has settled these awards through issuance of Avista Corp. common stock and intends to continue this practice. Both types of awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific market or performance conditions. Based on the level of attainment of the market or performance conditions, the amount of cash paid or common stock issued will range from 0 to 200 percent of the initial awards granted. Dividend equivalent rights are accumulated and paid out only on shares that have vested and have met the market and performance conditions.

The Company accounts for both the TSR awards and CEPS awards as equity awards and compensation cost for these awards is recognized over the requisite service period, provided the requisite service period is rendered. For TSR awards, if the market condition is not met at the end of the three-year service period, there will be no change in the cumulative amount of compensation cost recognized, since the awards are still considered vested even though the market metric was not met.

For CEPS awards, at the end of the three-year service period, if the internal performance metric of cumulative earnings per share is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The fair value of each TSR award is estimated on the date of grant using a statistical model incorporating the probability of meeting the market targets based on historical returns relative to a peer group. CEPS awards are valued at the close of market of the Company's common stock on the grant date.

The following table summarizes the number of grants, vested and unvested shares, earned shares (based on market metrics), and other pertinent information related to the Company's stock compensation awards for the years ended December 31:

	2025	2024	2023
Restricted Shares			
Shares granted during the year	141,618	82,433	76,806
Shares vested during the year	96,214	75,107	75,007
Unvested shares at end of year	190,979	158,464	152,140
Unrecognized compensation expense at end of year (in millions)	$ 4	$ 3	$ 3
TSR Awards			
TSR shares granted during the year	36,616	45,739	34,912
TSR shares vested during the year	28,760	64,640	61,456
TSR shares earned based on market metrics	—	35,552	44,863
Unvested TSR shares at end of year	72,574	77,530	96,915
Unrecognized compensation expense at end of year (in millions)	$ 1	$ 2	$ 2
CEPS Awards			
CEPS shares granted during the year	129,056	137,161	104,685
CEPS shares vested during the year	86,227	64,640	61,456
CEPS shares earned based on performance metrics	34,491	29,088	33,801
Unvested CEPS shares at end of year	236,873	232,486	161,235
Unrecognized compensation expense at end of year (in millions)	$ 7	$ 3	$ 2

Outstanding restricted, TSR and CEPS share awards include a dividend component paid in cash. A liability for the dividends payable related to these awards is accrued as dividends are announced throughout the life of the award. As of December 31, 2025 and 2024, the Company had recognized a liability of $2 million and $3 million, respectively, related to the dividend equivalents payable on the outstanding and unvested share grants.

Other Income—Net

Other income—net consisted of the following items for the years ended December 31 (dollars in millions):

	2025	2024	2023
Interest income	$ 5	$ 5	$ 6
Interest on regulatory deferrals	7	9	9
Equity-related AFUDC	11	9	7
Losses on investments	(12)	(7)	(3)
Other income	—	6	—
Total	$ 11	$ 22	$ 19

Earnings per Common Share

Basic earnings per common share is computed by dividing net income by the weighted-average number of common shares outstanding for the period. Diluted earnings per common share is calculated by dividing net income by diluted weighted-average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable under contingent stock awards. See Note 21 for earnings per common share calculations.

Cash and Cash Equivalents

For the purposes of the Consolidated Statements of Cash Flows, the Company considers all temporary investments with a maturity of three months or less when purchased to be cash equivalents.

Accounts Receivable and Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts.

The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in millions):

	2025	2024	2023
Allowance as of the beginning of the year	$ 5	$ 5	$ 6
Additions expensed during the year	7	7	7
Net deductions	(7)	(7)	(8)
Allowance as of the end of the year	$ 5	$ 5	$ 5

The Company has received grants from various government agencies to assist customers with their energy bills. The Company received these grant funds and applied them to customer accounts, reducing accounts receivable balances. These grants totaled $10 million in 2024 and $2 million in 2023. There were no grants received under these programs in 2025.

Utility Plant in Service

The cost of additions to utility plant in service, including an allowance for funds used during construction and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Asset Retirement Obligations

The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. In addition, if there are changes in the estimated timing or estimated costs of the AROs, adjustments are recorded during the period new information becomes available as an increase or decrease to the liability, with the offset recorded to the related long-lived asset. Upon retirement of the asset, the Company either settles the ARO for its recorded amount or recognizes a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the ratemaking process. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers (see Note 11 for further discussion of the Company's AROs).

The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense for which the Company has not recorded asset retirement obligations.

The Company records the amount of estimated retirement costs collected from customers (that do not represent legal or contractual obligations) and includes them as a non-current regulatory liability on the Consolidated Balance Sheets in the following amounts as of December 31 (dollars in millions):

	2025	2024
Regulatory liability for utility plant retirement costs	$ 468	$ 448

Goodwill

Goodwill arising from acquisitions represents the future economic benefit arising from other assets acquired in a business combination not individually identified and separately recognized. In 2025, the Company evaluated goodwill for impairment using a fair value to carrying amount comparison (Step 1). The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2025 and determined goodwill was not impaired at that time (carrying value was less than the determined fair value). No events or circumstances occurred between November 30, 2025 and December 31, 2025 that would more likely than not reduce the fair values of the reporting units below their carrying amounts. As of December 31, 2025 and December 31, 2024, the carrying amount of goodwill was $52 million. There are no accumulated impairment losses recognized to date.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Consolidated Balance Sheets measured at estimated fair value.

The WUTC and the IPUC issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and costs result in adjustments to retail rates through PGAs, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rate cases. The resulting regulatory assets associated with energy commodity derivative instruments are probable of recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts not considered derivatives are accounted for on the accrual basis until they are settled or realized unless there is a decline in the fair value of the contract determined to be other-than-temporary.

For interest rate swap transactions, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no impact on the income statement. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process.

The Company has multiple master agreements with a variety of entities allowing for cross-commodity netting of derivative agreements with the same counterparty (e.g., power derivatives can be netted with natural gas derivatives under certain conditions). In addition, some master agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Consolidated Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, some equity investments, as well as derivatives related to interest rate swaps and foreign currency exchange contracts, are reported at estimated fair value on the Consolidated Balance Sheets. See Note 18 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its consolidated financial statements in accordance with regulatory accounting practices because:

- rates for regulated services are established by or subject to approval by independent third-party regulators,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

Regulatory accounting practices require certain costs and/or obligations (such as incurred power and natural gas costs not currently reflected in rates, but expected to be recovered or refunded in the future), to be reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Consolidated Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. See Note 4 for discussion on decoupling revenue deferrals.

If at some point in the future the Company determines it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if the Company expected to recover these amounts from customers in the future.

See Note 23 for further details of regulatory assets and liabilities.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt. These costs are recorded as an offset to Long-Term Debt on the Consolidated Balance Sheets.

Unamortized Debt Repurchase Costs

Premiums paid or discounts received to repurchase debt are amortized over the remaining life of the original debt repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. These costs are recovered through retail rates as a component of interest expense.

Appropriated Retained Earnings

In accordance with the hydroelectric licensing requirements of section 10(d) of the Federal Power Act (FPA), the Company maintains an appropriated retained earnings account for earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

The appropriated retained earnings amounts included in retained earnings were as follows as of December 31 (dollars in millions):

	2025	2024
Appropriated retained earnings	$ 65	$ 62

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses loss contingencies that do not meet these conditions for accrual, if there is a reasonable possibility that a material loss may be incurred. As of December 31, 2025, the Company has not recorded significant amounts related to unresolved contingencies. See Note 22 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU 2023-06 "Disclosure Improvements—Codification Amendments in Response to the SEC's Disclosure Update and Simplification Initiative"

In October 2023, the FASB issued ASU 2023-06, which incorporates a variety of SEC required disclosures into the FASB Accounting Standards Codification (ASC). For entities subject to SEC's existing disclosure requirements, the effective date for each amendment will be the date on which the SEC removes the related disclosure from Regulation S-X or Regulation S-K, with early adoption permitted. If the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K by June 30, 2027, the disclosure requirements will be removed from the Codification. The requirements of the ASU will not have a material impact on the Company's financial statements.

ASU 2023-09 "Income Taxes (Topic 740)—Improvements to Income Tax Disclosures"

In December 2023, the FASB issued ASU 2023-09, requiring additional income tax disclosures. The additional disclosures include prescribed items presented in the income tax rate reconciliation, and further disaggregation of income taxes paid between federal, state and foreign taxes. The ASU became effective for fiscal years beginning after December 15, 2024, and the Company adopted with retrospective presentation. The expanded income tax disclosures have been included within Note 13.

ASU 2024-03 "Disaggregation of Income Statement Expenses"

In November 2024, the FASB issued ASU 2024-03, requiring additional footnote disclosures disaggregating certain expenses included on the income statement. The ASU is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027, and early adoption is permitted. The Company is in the process of evaluating the impact of the ASU; however, it has determined it will not early adopt as of December 31, 2025.

ASU 2025-05 "Measurement of Credit Losses for Accounts Receivable and Contract Assets"

In July 2025, the FASB issued ASU 2025-05, providing a practical expedient that may be elected to assume current conditions as of the balance sheet date will remain unchanged for the remaining life of the receivable when developing an estimate of expected credit losses on accounts receivable arising from contracts with customers. The ASU is effective for annual reporting periods beginning after December 15, 2025 and interim reporting periods within those annual periods, and early adoption is permitted. The Company has elected to utilize the practical expedient, effective January 1, 2026, and does not expect a material impact to the financial statements.

ASU 2025-06 "Targeted Improvements to the Accounting for Internal-Use Software"

In September 2025, the FASB issued ASU 2025-06, which updates the capitalization criteria for internally developed software projects. The ASU is effective for annual reporting periods beginning after December 15, 2027 and interim reporting periods within those annual periods, and early adoption is permitted. The Company is in the process of evaluating the impact of the ASU; however, it has determined it will not early adopt as of December 31, 2025.

ASU 2025-10 "Accounting for Government Grants Received by Business Entities"

In December 2025, the FASB issued ASU 2025-10, which establishes authoritative accounting guidance for government grants received by a business entity. The ASU is effective for annual reporting periods beginning after December 15, 2028 and interim reporting periods within those annual periods, and early adoption is permitted. The Company is in the process of evaluating the impact of the ASU; however, it has determined it will not early adopt as of December 31, 2025.

NOTE 3. BALANCE SHEET COMPONENTS

Inventory

Inventories of materials and supplies, emission allowances, stored natural gas and fuel stock are recorded at average cost and consisted of the following as of December 31 (dollars in millions):

	2025	2024
Materials and supplies	$ 87	$ 99
Emission allowances	136	79
Stored natural gas	8	10
Fuel stock	5	5
Total	$ 236	$ 193

Other Current Assets

Other current assets consisted of the following as of December 31 (dollars in millions):

	2025	2024
Prepayments	$ 56	$ 37
Income taxes receivable	39	32
Derivative assets—net of collateral	8	11
Other	16	11
Total	$ 119	$ 91

Other Property and Investments—Net and Other Non-Current Assets

Other property and investments—net and other non-current assets consisted of the following as of December 31 (dollars in millions):

	2025	2024
Equity investments	$ 148	$ 157
Operating lease ROU assets	64	66
Finance lease ROU assets	29	33
Non-utility property	12	33
Notes receivable	12	16
Long-term prepaid license fees	18	18
Pension assets	61	35
Investment in affiliated trust	12	12
Deferred compensation assets	9	9
Other	23	20
Total	$ 388	$ 399

Other Current Liabilities

Other current liabilities consisted of the following as of December 31 (dollars in millions):

	2025	2024
Accrued taxes other than income taxes	$ 33	$ 34
Employee paid time off accruals	34	32
Accrued interest	27	24
Pensions and other postretirement benefits	16	15
Derivative liabilities	18	14
Customer deposits	19	14
Other	54	51
Total	$ 201	$ 184

Other Non-Current Liabilities and Deferred Credits

Other non-current liabilities and deferred credits consisted of the following as of December 31 (dollars in millions):

	2025	2024
Operating lease liabilities	$ 60	$ 62
Finance lease liabilities	32	35
Deferred investment tax credits	27	28
Climate Commitment Act obligations	131	77
Asset retirement obligations	16	18
Derivative liabilities	10	12
Other	29	21
Total	$ 305	$ 253

NOTE 4. REVENUE

The core principle of the revenue recognition model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation.

Utility Revenues

Revenue from Contracts with Customers

General

The majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers, which has two performance obligations, (1) having service available for a specified period (typically a month at a time) and (2) the delivery of energy to customers. The total energy price generally has a fixed component (basic charge) related to having service available and a usage-based component, related to the delivery and consumption of energy. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant utility commission authorization determine the charges the Company may bill the customer. Since all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately.

In addition, the sale of electricity and natural gas is governed by the various state utility commissions, which set rates, charges, terms and conditions of service, and prices. Collectively, these rates, charges, terms and conditions are included in a "tariff," which governs all aspects of the provision of regulated services. Tariffs are only permitted to be changed through a rate-setting process involving an independent, third-party regulator empowered by statute to establish rates that bind customers. Thus, all regulated sales by the Company are conducted subject to the regulator-approved tariff.

Tariff sales involve the current provision of commodity service (electricity and/or natural gas) to customers for a price that generally has a basic charge and a usage-based component. Tariff rates also include certain pass-through costs to customers such as natural gas costs, retail revenue credits and other miscellaneous regulatory items that do not impact net income, but can cause total revenue to fluctuate significantly up or down compared to previous periods. The commodity is sold and/or delivered to and consumed by the customer simultaneously, and the provisions of the relevant tariff determine the charges the Company may bill the customer, payment due date, and other pertinent rights and obligations of both parties. Generally, tariff sales do not involve a written contract. Since all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized at that time.

Revenues from contracts with customers are presented in the Consolidated Statements of Income in the line item "Utility revenues, exclusive of alternative revenue programs."

Unbilled Revenue from Contracts with Customers

The determination of the volume of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month (once per month for each individual customer). At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. The Company's estimate of unbilled revenue is based on:

- the number of customers,
- tariff rates,
- meter reading dates,
- actual native load for electricity,
- actual throughput for natural gas, and
- electric line losses and natural gas system losses.

Any difference between actual and estimated revenue is recorded in the following month when the meter reading and customer billing occurs.

Accounts receivable includes unbilled energy revenues of the following amounts as of December 31 (dollars in millions):

	2025	2024
Unbilled accounts receivable	$ 85	$ 75

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts that are not accounted for as derivatives and are considered revenue from contracts with customers. Revenue is recognized as energy is delivered to the customer or the service is available for a specified period of time, consistent with the discussion of rate regulated sales above.

Alternative Revenue Programs (Decoupling)

Alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires the presentation of revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the Consolidated Statements of Income. The Company's decoupling mechanisms (also known as a FCA in Idaho) qualify as alternative revenue programs. Decoupling revenue deferrals are recognized in the Consolidated Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset or liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for an alternative revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the Consolidated Statements of Income. Amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. The amounts expected to be collected from customers within 24 months represents an estimate made by the Company on an ongoing basis due to it being based on the volumes of electric and natural gas sold to customers on a go-forward basis.

The Company records alternative program revenues under the gross method, which is to amortize the decoupling regulatory asset/liability to the alternative revenue program line item on the Consolidated Statements of Income as it is collected from or refunded to customers. The cash passing between the Company and the customers is presented in revenue from contracts with customers since it is a portion of the overall tariff paid by customers. This method results in a gross-up to both revenue from contracts with customers and revenue from alternative revenue programs, but has a net zero impact on total revenue. Depending on whether the previous deferral balance being amortized was a regulatory asset or regulatory liability, and depending on the size and direction of the current year deferral of surcharges and/or rebates to customers, it could result in negative alternative revenue program revenue during the year.

Derivative Revenue

Most wholesale electric and natural gas transactions (including both physical and financial transactions), and the sale of fuel are considered derivatives, which are disclosed separately from revenue from contracts with customers. Revenue is recognized for these items upon the settlement/expiration of the derivative contract. Derivative revenue includes transactions entered into and settled within the same month.

Other Utility Revenue

Other utility revenue, which includes rent, sales of materials, late fees and other charges, are not considered revenues from contracts with customers. This revenue is not so considered, since it is not received pursuant to contracts under which customers obtain goods or services that are an output of the Company's ordinary activities in exchange for consideration. As such, these revenues are presented separately from revenue from contracts with customers.

Other Considerations for Utility Revenues

Gross Versus Net Presentation

Revenues and resource costs from Avista Utilities' settled energy contracts "booked out" (not physically delivered) are reported on a net basis as part of derivative revenues.

Utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) are imposed on Avista Utilities as opposed to being imposed on customers; therefore, Avista Utilities is the taxpayer and records these transactions on a gross basis in revenue from contracts with customers and operating expense (taxes other than income taxes). The utility-related taxes collected from customers at AEL&P are imposed on the customers rather than AEL&P; therefore, the customers are the taxpayers and AEL&P is acting as their agent. As such, these transactions at AEL&P are presented on a net basis within revenue from contracts with customers.

Utility-related taxes included in revenue from contracts with customers were as follows for the years ended December 31 (dollars in millions):

	2025	2024	2023
Utility-related taxes	$ 82	$ 81	$ 75

Significant Judgments and Unsatisfied Performance Obligations

The only significant judgments involving revenue recognition are estimates surrounding unbilled revenue and receivables from contracts with customers and estimates surrounding the amount of decoupling revenues that will be collected from customers within 24 months (discussed above).

The Company has certain capacity arrangements, where the Company has a contractual obligation to provide either electric or natural gas capacity to its customers for a fixed fee. Most of these arrangements are paid for in arrears by the customers and do not result in deferred revenue and only result in receivables from the customers. The Company has one capacity agreement where the customer makes payments throughout the year. As of December 31, 2025, the Company estimates it had unsatisfied capacity performance obligations of $25 million, which will be recognized as revenue in future periods as the capacity is provided to the customers. These performance obligations are not reflected in the financial statements, as the Company has not received payment for these services.

Disaggregation of Total Operating Revenue

The following table disaggregates total operating revenue by segment and source for the years ended December 31 (dollars in millions):

	2025	2024	2023
AVISTA UTILITIES			
Revenue from contracts with customers	$ 1,625	$ 1,570	$ 1,486
Derivative revenues	221	249	199
Alternative revenue programs	23	34	5
Deferrals and amortizations for rate refunds to customers	(13)	1	1
Other utility revenues	60	33	12
Total Avista Utilities	1,916	1,887	1,703
AEL&P			
Revenue from contracts with customers	47	49	47
Other utility revenues	—	1	1
Total AEL&P	47	50	48
Other			
Other revenues	1	1	1
Total operating revenues	$ 1,964	$ 1,938	$ 1,752

Utility Revenue from Contracts with Customers by Type and Service

The following table disaggregates revenue from contracts with customers associated with the Company's electric operations for the years ended December 31 (dollars in millions):

	2025			2024			2023		
	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility
ELECTRIC OPERATIONS									
Revenue from contracts with customers									
Residential	$ 550	$ 22	$ 572	$ 473	$ 22	$ 495	$ 425	$ 20	$ 445
Commercial and governmental	402	25	427	369	27	396	344	27	371
Industrial	142	—	142	131	—	131	110	—	110
Public street and highway lighting	9	—	9	9	—	9	8	—	8
Total retail revenue	1,103	47	1,150	982	49	1,031	887	47	934
Transmission	30	—	30	38	—	38	33	—	33
Other revenue from contracts with customers	29	—	29	40	—	40	45	—	45
Total electric revenue from contracts with customers	$ 1,162	$ 47	$ 1,209	$ 1,060	$ 49	$ 1,109	$ 965	$ 47	$ 1,012

The following table disaggregates revenue from contracts with customers associated with the Company's natural gas operations for the years ended December 31 (dollars in millions):

	2025 Avista Utilities	2024 Avista Utilities	2023 Avista Utilities
NATURAL GAS OPERATIONS			
Revenue from contracts with customers			
Residential	$ 291	$ 317	$ 326
Commercial	137	163	164
Industrial and interruptible	12	13	17
Total retail revenue	440	493	507
Transportation	13	11	8
Other revenue from contracts with customers	10	6	6
Total natural gas revenue from contracts with customers	$ 463	$ 510	$ 521

NOTE 5. LEASES

The core principle of lease accounting is that an entity should recognize the ROU assets and liabilities from leases on the balance sheet and depreciate or amortize the asset and liability over the term of the lease, as well as provide disclosure to enable users of the consolidated financial statements to assess the amount, timing, and uncertainty of cash flows from leases.

Significant Judgments and Assumptions

The Company determines if an arrangement is a lease, as well as its classification, at its inception.

ROU assets represent the Company's right to use an underlying asset for the lease term, and lease liabilities represent the Company's obligation to make lease payments. Operating and finance lease ROU assets and lease liabilities are recognized at the commencement date of the agreement based on the present value of lease payments over the lease term. As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at the commencement date to determine the present value of lease payments. The implicit rate is used when it is readily determinable. The operating and finance lease ROU assets also include lease payments made and exclude lease incentives, if any, that accrue to the benefit of the lessee.

Lease terms may include options to extend or terminate the lease when it is reasonably certain the Company will exercise that option. Lease expense is recognized on a straight-line basis over the lease term. The difference between lease expense and cash paid for leased assets is recognized as a regulatory asset or regulatory liability.

Description of Leases

Operating Leases

The Company's most significant operating lease is with the State of Montana associated with submerged land around the Company's hydroelectric facilities in the Clark Fork River basin, which expires in 2046. The terms of this lease are subject to adjustment—depending on the outcome of ongoing litigation between the State of Montana and NorthWestern. In addition, the State of Montana and Avista Corp. were engaged in litigation regarding lease terms, including how much money, if any, the State of Montana should return to Avista Corp.; however, that litigation was dismissed as premature pending the outcome of the ongoing litigation between the State of Montana and NorthWestern. Any reduction in future lease payments or the return to Avista Corp. of amounts previously paid will be included in the future ratemaking process.

In addition to the lease with the State of Montana, the Company has other operating leases for land associated with its utility operations, as well as communication sites which support network and radio communications within its service territory. The Company's leases have remaining terms of 1 to 69 years. Most of the Company's leases include options to extend the lease term for periods of 5 to 50 years. Options are exercised at the Company's discretion.

Certain of the Company's lease agreements include rental payments which are periodically adjusted over the term of the agreement based on the consumer price index. The Company's lease agreements do not include material residual value guarantees or material restrictive covenants.

The Company has entered into a PPA agreement with Rathdrum Power, LLC for the output of the Lancaster Plant through 2041. The PPA meets the accounting definition of a lease. However, since all payments are variable in nature, based on capacity, usage, or performance of the plant, there is no lease obligation or corresponding ROU asset recorded by the Company related to this agreement. The variable lease costs related to this agreement are included in resource costs on the Consolidated Statements of Income.

Avista Corp. does not record leases with a term of 12 months or less on the Consolidated Balance Sheets. Total short-term lease costs for 2025 are immaterial.

Finance Lease

AEL&P has a PPA which is a finance lease for accounting purposes related to the Snettisham Hydroelectric Project, which expires in 2034. For ratemaking purposes, this lease is an operating lease with a constant level of annual rental expense (straight line rent expense). Because of this regulatory treatment, differences between the operating lease expense for ratemaking purposes and the expenses recognized under GAAP (interest expense and amortization of the finance lease ROU asset) are recorded as a regulatory asset and amortized during the later years of the lease when the finance lease expense is less than the operating lease expense included in base rates. The amortization of the ROU asset is included in depreciation and amortization and the interest associated with the lease liability is included in interest expense on the Consolidated Statements of Income.

Operating and Finance Lease Balances in the Financial Statements

The components of lease expense were as follows for the year ended December 31 (dollars in millions):

	2025	2024	2023
Operating lease cost:			
Fixed lease cost (Other operating expenses)	$ 5	$ 5	$ 5
Variable lease cost (Other operating expenses and Resource costs)	31	31	25
Total operating lease cost	$ 36	$ 36	$ 30
Finance lease cost:			
Amortization of ROU asset (Depreciation and amortization)	$ 4	$ 4	$ 4
Interest on lease liabilities (Interest expense)	2	2	2
Total finance lease cost	$ 6	$ 6	$ 6

Supplemental cash flow information related to leases was as follows for the year ended December 31 (dollars in millions):

	2025	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash outflows:			
Operating lease payments	$ 5	$ 5	$ 5
Interest on finance lease	2	2	2
Total operating cash outflows	$ 7	$ 7	$ 7
Finance cash outflows:			
Principal payments on finance lease	$ 3	$ 3	$ 3

Supplemental balance sheet information related to leases was as follows for December 31 (dollars in millions):

	December 31, 2025	December 31, 2024
Operating Leases		
Operating lease ROU assets (Other property and investments—net and other non-current assets)	$ 64	$ 66
Other current liabilities	$ 5	$ 4
Other non-current liabilities and deferred credits	60	62
Total operating lease liabilities	$ 65	$ 66
Finance Leases		
Finance lease ROU assets (Other property and investments—net and other non-current assets)	$ 29	$ 33
Other current liabilities	$ 4	$ 4
Other non-current liabilities and deferred credits	32	35
Total finance lease liabilities	$ 36	$ 39
Weighted-Average Remaining Lease Term		
Operating leases	20 years	21 years
Finance leases	8 years	4 years
Weighted-Average Discount Rate		
Operating leases	4.32%	4.30%
Finance leases	3.14%	3.46%

Maturities of lease liabilities (including principal and interest) were as follows as of December 31, 2025 (dollars in millions):

	Operating Leases	Finance Leases
2026	$ 5	$ 5
2027	5	6
2028	5	6
2029	5	6
2030	5	5
Thereafter	75	16
Total lease payments	$ 100	$ 44
Less: imputed interest	(35)	(8)
Total	$ 65	$ 36

NOTE 6. VARIABLE INTEREST ENTITIES

Under GAAP, a limited partnership or similar legal entity that is the functional equivalent of a limited partnership is considered a VIE regardless of whether it otherwise qualifies as a voting interest entity unless a simple majority or lower threshold of the "unrelated" limited partners (i.e., parties other than the general partner, entities under common control with the general partner, and other parties acting on behalf of the general partner) have substantive kick-out rights (including liquidation rights) or participating rights.

The Company has investments in limited partnerships (or the functional equivalent) where Avista Corp. is a limited partner investor in an investment fund where the general partner makes all of the investment and operating decisions with regards to the partnership and fund. To remove the general partner from any of the funds, approval from greater than a simple majority of the limited partners is required. As such, the limited partners do not have substantive kick-out rights and these investments are considered VIEs. Consolidation of these VIEs by Avista Corp. is not required because the Company does not have majority ownership in any of the funds, it does not have the power to direct activities of the funds, and it does not have the power to appoint executive leadership, including the board of directors.

Avista Corp. participates in profits and losses of the investment funds based on its ownership percentage and its losses are capped at its total initial investment in the funds. Equity investments in VIEs are accounted for under the equity method (see Note 7). As of December 31, 2025, Avista Corp. has invested $83 million in these investment funds, with an additional commitment of $17 million remaining to be invested. The Company is not allowed to withdraw capital contributions from an investment fund until after that fund expiration date and all liabilities of that fund are settled. The expiration dates range from 2025 to 2036, with some investments having no termination date (as they are perpetual). As of December 31, 2025, the Company has a total carrying amount of $82 million in these VIEs, including $72 million of equity investments and $10 million of notes receivable.

NOTE 7. EQUITY INVESTMENTS

The Company has equity investment holdings that are accounted for under the equity method, at fair value, or using the fair value measurement alternative provided for in ASC 321, adjusting cost for impairment and observable price changes.

The following table summarizes Avista Corp.'s equity investments, which are included in "Other property and investments—net and other non-current assets" on the Consolidated Balance Sheets as of December 31 (dollars in millions):

	2025	2024
Equity method investments	$ 70	$ 77
Investments without readily determinable fair value		
Non-recurring fair value	29	27
Recurring fair value	49	53
Total	$ 148	$ 157

Equity Method Investments

The Company has investments in limited partnerships (or the functional equivalent) where Avista Corp. is a limited partner investor in an investment fund. Holdings in these investment funds are accounted for under the equity method. Underlying investments held by the funds are recorded at fair value by the fund, and Avista Corp. recognizes its share of the fund's profits and losses based on its ownership percentage.

The Company also has ownership in joint ventures with underlying holdings in real estate, which are accounted for under the equity method.

The Company's earnings and losses related to equity method investments are included in "Other income—net" on the Consolidated Statements of Net Income.

Investments Without Readily Determinable Fair Value

The Company has investments that do not qualify for equity method treatment, and for which fair value is not readily determinable. The Company has elected the measurement alternative for a majority of these investments, adjusting the recorded value on a non-recurring basis as a result of observable transactions involving the underlying asset. The observable transaction indicates an updated fair value, and the Company adjusts carrying value to fair value at this point in time. The fair value of these assets is determined using the market approach, and these assets are considered level 2 on the fair value hierarchy (see Note 18 for a description of the fair value hierarchy).

The Company has elected to record two investments at fair value on a recurring basis. These equity investments are considered Level 3 on the fair value hierarchy. See further discussion of Level 3 equity investments, including valuation methods and significant inputs, as included in Note 18.

Realized and unrealized gains or losses in equity investments are included in net income.

The following table summarizes net unrealized gains (losses) related to investments without readily determinable fair value held as of the end of the respective period for the years ended December 31 (dollars in millions):

	2025	2024	2023
Investments recorded at non-recurring fair value	$ 2	$ —	$ —
Investments recorded at recurring fair value	(4)	—	(4)
Total	$ (2)	$ —	$ (4)

Net unrealized gains recorded related to investments recorded at non-recurring fair value result from identified observable transactions. On a cumulative basis, the Company has recognized a net gain of $17 million for fair value adjustments to investments recorded at non-recurring fair value held at December 31, 2025.

NOTE 8. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated commodity derivative instruments. Avista Corp. utilizes instruments that meet the definition of a derivative under U.S. GAAP, such as forwards, futures, swaps and options to manage the various risks relating to these commodity price exposures. Avista Corp. has an energy resources risk policy and control procedures to manage these risks.

As part of Avista Corp.'s resource procurement and management operations in the electric business, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value through wholesale market transactions. These include sales and purchases of electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging a portion of the related financial risks. These transactions range from terms of intra-hour up to multiple years.

As part of its resource procurement and management of its natural gas business, Avista Corp. makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Corp.'s distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. Based on these projections, Avista Corp. plans and executes a series of transactions to hedge a portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as three natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Avista Corp. plans for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. Avista Corp. generally has more pipeline and storage capacity than what is needed during periods other than a peak day. Avista Corp. optimizes its natural gas resources by using market opportunities to generate economic value that mitigates the fixed costs. Avista Corp. also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that Avista Corp. should buy or sell natural gas at other times during the year, Avista Corp. engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2025 expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
	Physical [1]	Financial [1]	Physical [1]	Financial [1]	Physical [1]	Financial [1]	Physical [1]	Financial [1]
Year	MWh	MWh	mmBTUs	mmBTUs	MWh	MWh	mmBTUs	mmBTUs
2026	6	—	30,523	30,535	373	328	2,325	543
2027	—	—	14,558	14,443	—	—	1,393	—
2028	—	—	4,413	5,393	—	—	1,013	—

As of December 31, 2025, there are no energy commodity derivative contracts outstanding with expected deliveries after 2028.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2024 that were expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2025	7	—	27,993	39,483	427	420	1,897	1,963
2026	—	—	17,560	13,175	—	—	—	—
2027	—	—	7,555	2,250	—	—	—	—

As of December 31, 2024, there were no energy commodity derivative contracts outstanding with expected deliveries after 2027.

(1) Physical transactions represent commodity derivative transactions in which Avista Corp. will take or make delivery of either electricity or natural gas; financial transactions represent financial derivative instruments that are settled in cash with no physical delivery of the underlying commodity, such as futures, swaps, or options contracts.

The electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are scheduled to be delivered and will be included in the various deferral and recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to be recovered through retail rates from customers.

Foreign Currency Exchange Derivatives

A significant portion of Avista Corp.'s natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Corp.'s short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices. The short-term natural gas transactions are settled within 60 days with U.S. dollars. Avista Corp. hedges a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. The foreign currency exchange derivatives and the unhedged foreign currency risk have not had a material effect on Avista Corp.'s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency exchange derivatives outstanding as of December 31 (dollars in millions):

	2025	2024
Number of contracts	26	22
Notional amount (in United States dollars)	$ 6	$ 2
Notional amount (in Canadian dollars)	4	2

Summary of Outstanding Derivative Instruments

The amounts recorded on the Consolidated Balance Sheets as of December 31, 2025 and December 31, 2024 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of energy commodity derivative instruments recorded on the Consolidated Balance Sheets as of December 31, 2025 (dollars in millions):

Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Fair Value Net Asset (Liability) on Balance Sheet
Other current assets	$ 8	$ —	$ —	$ 8
Other current liabilities	7	(33)	8	(18)
Other non-current liabilities and deferred credits	2	(14)	2	(10)
Total derivative instruments recorded on the balance sheet	$ 17	$ (47)	$ 10	$ (20)

The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheets as of December 31, 2024 (dollars in millions):

Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Fair Value Net Asset (Liability) on Balance Sheet
Interest rate swap derivatives				
Other current assets	$ 1	$ —	$ —	$ 1
Energy commodity derivatives				
Other current assets	10	—	—	10
Other current liabilities	11	(48)	23	(14)
Other non-current liabilities and deferred credits	2	(16)	1	(13)
Total derivative instruments recorded on the balance sheet	$ 24	$ (64)	$ 24	$ (16)

Exposure to Demands for Collateral

Avista Corp.'s derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement. In the event of changes in market prices or a downgrade in Avista Corp.'s credit ratings or other established credit criteria, or, in some cases, if the counterparty has reasonable grounds to believe that there has been a material change in Avista Corp.'s creditworthiness, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. In addition, these contracts contain customary events of default (including cross-defaults to indebtedness and other obligations) and termination provisions. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents collateral outstanding related to its energy commodity derivative instruments as of December 31 (dollars in millions):

	2025	2024
Cash collateral posted	$ 12	$ 24
Letters of credit outstanding	14	12

Certain of Avista Corp.'s derivative instruments contain provisions requiring Avista Corp. to maintain an "investment grade" credit rating from the major credit rating agencies. If Avista Corp.'s credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions.

The following table presents the aggregate fair value of energy commodity derivative instruments with credit-risk-related contingent features in a liability position and the amount of additional collateral Avista Corp. could be required to post as of December 31 (dollars in millions):

	2025
Liabilities with credit-risk-related contingent features	$ 20
Additional collateral to post	20

NOTE 9. JOINTLY OWNED ELECTRIC FACILITIES

The Company had a 15 percent ownership interest in Units 3 & 4 of Colstrip, and provided financing for its ownership interest in the project. Effective January 1, 2026, the Company transferred its ownership to NorthWestern. The Company has retained responsibility for remediation obligations in existence at the time the transaction closed. See further discussion of the transaction within Note 22.

Pursuant to the ownership and operating agreements among the co-owners, the Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income.

The Company's share of utility plant in service for Colstrip and accumulated depreciation (inclusive of the ARO assets and accumulated amortization) were as follows as of December 31 (dollars in millions):

	2025	2024
Utility plant in service	$ 401	$ 401
Accumulated depreciation	(382)	(355)

The Company retained ownership of certain transmission assets subsequent to transferring its ownership interest in Units 3 & 4 to NorthWestern, which are included in amounts above. In addition, the Company has reclassified certain amounts to be recovered or returned to customers subsequent to the ownership transfer to regulatory assets and liabilities as of December 31, 2025.

See Note 11 for further discussion of AROs.

While the obligations and liabilities with respect to Colstrip have been shared among the co-owners on a pro-rata basis, many of the environmental liabilities are joint and several under the law, so that if any co-owner failed to pay its share of such liability, the other co-owners (or any one of them) could be required to pay the defaulting co-owner's share (or the entire liability).

NOTE 10. PROPERTY, PLANT AND EQUIPMENT

Net Utility Property

Net utility property consisted of the following as of December 31 (dollars in millions):

	2025	2024
Utility plant in service	$ 8,591	$ 8,180
Construction work in progress	303	238
Total	8,894	8,418
Less: Accumulated depreciation and amortization	2,575	2,431
Total net utility property	$ 6,319	$ 5,987

Gross Property, Plant and Equipment

The gross balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in millions):

	2025	2024
Avista Utilities:		
Electric production	$ 1,588	$ 1,523
Electric transmission	1,158	1,105
Electric distribution	2,784	2,580
Electric construction work-in-progress (CWIP) and other	494	452
Electric total	6,024	5,660
Natural gas underground storage	65	63
Natural gas distribution	1,700	1,624
Natural gas CWIP and other	98	95
Natural gas total	1,863	1,782
Common plant (including CWIP)	780	760
Total Avista Utilities	8,667	8,202
AEL&P:		
Electric production	141	120
Electric transmission	23	23
Electric distribution	39	36
Electric CWIP and other	13	26
Electric total	216	205
Common plant	11	11
Total AEL&P	227	216
Total gross utility property	$ 8,894	$ 8,418

NOTE 11. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

- restore coal ash containment ponds and coal holding areas at Colstrip,
- cap a landfill at the Kettle Falls Plant, and
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

The Company transferred its ownership interest in Colstrip to NorthWestern on January 1, 2026. The Company retained responsibility for its share of the liabilities giving rise to the Colstrip AROs existing as of the transfer date.

In 2015, the EPA issued a final rule regarding CCRs. Colstrip produces this byproduct. The CCR rule has been the subject of ongoing litigation. In August 2018, the D.C. Circuit struck down provisions of the rule. The rule includes technical requirements for CCR landfills and surface impoundments. The Colstrip owners developed a multi-year compliance plan to address the CCR requirements and existing state obligations.

In April 2024 and January 2025, the EPA issued additional final rules building on the 2015 regulations and regulating CCR management units at active and inactive power plants. The Colstrip owners are performing analyses to determine whether any potential changes to the existing remediation efforts are required. Based on the results of these analyses to date, the Company believes there will not be a material change to the asset retirement obligation for Colstrip related to these final rules.

The actual asset retirement costs related to the CCR rule requirements may vary substantially from the estimates used to record the ARO due to the uncertainty and evolving nature of the compliance strategies that will be used and the availability of data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. The Company updates its estimates as new information becomes available. The Company expects to seek recovery of costs related to complying with the CCR rule through the ratemaking process.

In addition to the above, under a 2018 Administrative Order on Consent and ongoing negotiations with the Montana Department of Ecological Quality, the owners of Colstrip are required to provide financial assurance, primarily in the form of surety bonds, to secure each owner's pro-rata share of various anticipated closure and remediation of the ash ponds and coal holding areas. The amount of financial assurance required of each owner may, like the ARO, vary substantially due to the uncertainty and evolving nature of anticipated closure and remediation activities, and as those activities are completed over time.

The following table documents the changes in the Company's asset retirement obligation during the years ended December 31 (dollars in millions):

	2025	2024	2023
Asset retirement obligation at beginning of year	$ 18	$ 18	$ 16
Liabilities incurred	—	—	2
Liabilities settled	(3)	(1)	—
Accretion expense	1	1	—
Asset retirement obligation at end of year	$ 16	$ 18	$ 18

NOTE 12. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities. AEL&P participates in a defined contribution multiemployer plan for its union workers and a defined contribution money purchase pension plan for its nonunion workers. None of the subsidiary retirement plans, individually or in the aggregate, are significant to Avista Corp.

Avista Utilities

The Company has a defined benefit pension plan covering the majority of regular full-time non-union employees at Avista Utilities hired prior to January 1, 2014 and regular full-time union employees that were hired prior to January 1, 2024. Employees eligible for the plan continue to accrue benefits. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. Non-union employees hired on or after January 1, 2014 and union employees hired on or after January 1, 2024 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts currently deductible for income tax purposes. The Company contributed $10 million in cash each year to the pension plan in 2025, 2024, and 2023. The Company expects to contribute $10 million in cash to the pension plan in 2026.

In 2024, the Company offered pension participants an election to leave the pension plan for an alternative defined contribution 401(k) plan. In April 2024, it was determined that due to the number of participants electing to leave the pension plan, as well as the resulting decrease in expected future service, this event resulted in a curtailment of the pension plan, and an associated gain of $1 million for the reduction in the benefit obligation. This gain was offset against the unrecognized net actuarial loss (and recorded within a regulatory asset). The curtailment triggered a remeasurement of pension plan.

The remeasurement did not have a material impact on the Company's financial condition or results of operations.

The Company has a SERP providing additional pension benefits to certain executive officers and certain key employees of the Company. The SERP provides benefits to individuals whose benefits under the defined benefit pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company expects benefit payments under the pension plan and the SERP will total (dollars in millions):

	2026	2027	2028	2029	2030	Total 2031-2035
Expected benefit payments	$ 46	$ 46	$ 47	$ 47	$ 48	$ 249

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

The Company provides certain health care and life insurance benefits for eligible retired employees hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years employees provide services. The liability and expense of this plan are included as other postretirement benefits. Non-union employees hired on or after January 1, 2014, will have access to the retiree medical plan upon retirement; however, Avista Corp. will no longer provide a contribution toward their medical premium.

The Company has a Health Reimbursement Arrangement (HRA) to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on the employee's years of service and ending salary. The liability and expense of the HRA are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer's designated beneficiary will receive a payment equal to twice the executive officer's annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer's total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

The Company expects benefit payments under other postretirement benefit plans will total (dollars in millions):

	2026	2027	2028	2029	2030	Total 2031-2035
Expected benefit payments	$ 6	$ 6	$ 7	$ 7	$ 7	$ 38

The Company expects to contribute $6 million to other postretirement benefit plans in 2026. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following tables set forth the pension and other postretirement benefit plan disclosures as of December 31, 2025 and 2024 and the components of net periodic benefit costs for the years ended December 31, 2025, 2024 and 2023 (dollars in millions):

	Pension Benefits		Other Postretirement Benefits	
	2025	2024	2025	2024
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 600	$ 585	$ 117	$ 122
Service cost	16	16	2	3
Interest cost	35	34	7	7
Actuarial (gain)/loss (1)	15	2	(3)	(9)
Plan change	—	—	1	—
Benefits paid	(44)	(36)	(8)	(6)
Curtailments	—	(1)	—	—
Benefit obligation as of end of year (2)	$ 622	$ 600	$ 116	$ 117
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 608	$ 590	$ 67	$ 58
Actual return on plan assets	80	42	8	9
Employer contributions	10	10	—	—
Benefits paid	(42)	(34)	—	—
Fair value of plan assets as of end of year (2)	$ 656	$ 608	$ 75	$ 67
Funded status	$ 34	$ 8	$ (41)	$ (50)
Amounts recognized in the Consolidated Balance Sheets:				
Other non-current assets	$ 61	$ 35	$ —	$ —
Other current liabilities	(2)	(2)	(1)	(1)
Non-current liabilities	(25)	(25)	(40)	(49)
Net amount recognized	$ 34	$ 8	$ (41)	$ (50)
Accumulated pension benefit obligation (2)	$ 535	$ 522		
Accumulated postretirement benefit obligation:				
For retirees			$ 64	$ 67
For fully eligible employees			$ 18	$ 16
For other participants			$ 34	$ 34
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 3	$ 3	$ 1	$ —
Unrecognized net actuarial loss (gain)	52	70	(4)	2
Total	55	73	(3)	2
Less regulatory asset	(54)	(73)	3	(2)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 1	$ —	$ —	$ —

(1) The change in the pension benefit obligation related to actuarial loss is primarily related to actual investment returns differing from our assumptions, partially offset by financial and demographic assumption changes.

(2) As of December 31, 2025, the SERP had a projected benefit obligation of $27 million and an accumulated benefit obligation of $25 million, with no plan assets.

	Pension Benefits		Other Postretirement Benefits	
	2025	2024	2025	2024
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	5.96%	6.13%	6.11%	6.09%
Discount rate for annual expense	6.13%	5.86%	6.09%	5.83%
Expected long-term return on plan assets	7.40%	7.80%	6.60%	6.70%
Rate of compensation increase	5.07%	5.19%		
Medical cost trend pre-age 65—initial			7.00%	6.50%
Medical cost trend pre-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2034	2031
Medical cost trend post-age 65—initial			7.00%	6.50%
Medical cost trend post-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2034	2031

	Pension Benefits			Other Postretirement Benefits		
	2025	2024	2023	2025	2024	2023
Components of net periodic benefit cost:						
Service cost [(1)]	$ 16	$ 16	$ 14	$ 2	$ 3	$ 2
Interest cost	35	34	33	7	7	7
Expected return on plan assets	(44)	(45)	(44)	(4)	(4)	(3)
Amortization of prior service cost (credit)	1	—	1	—	(1)	(1)
Net loss recognition	3	2	5	—	—	—
Net periodic benefit cost	$ 11	$ 7	$ 9	$ 5	$ 5	$ 5

(1) Total service cost in the table above is recorded to the same accounts as labor expense. Labor and benefits expense is recorded to various projects based on whether the work is a capital project or an operating expense. Approximately 45 percent of all labor and benefits is capitalized to utility property and 55 percent is expensed to utility other operating expenses.

Pension costs other than service costs are presented in the Consolidated Statements of Income in the line item "Other income—net."

Plan Assets

The Finance Committee of the Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested in mutual funds, and trusts and partnerships that hold marketable debt and equity securities and real estate. In seeking to obtain a return that aligns with the funded status of the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and investment ranges for each asset class of 55 percent in equity securities, 40 percent in debt securities, and 5 percent in real estate. The target investment allocation percentages are typically the midpoint of the established range.

The fair value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the reported last sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, the investment manager estimates fair value based upon other inputs (including valuations of securities comparable in coupon, rating, maturity and industry).

Pension plan and other postretirement plan assets with fair values are measured using net asset value (NAV) are excluded from the fair value hierarchy and included as reconciling items in the tables below.

The plan's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. Most of the plan's investments in closely held investments and partnership interests have redemption limitations ranging from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days.

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2025 at fair value (dollars in millions):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 9	$ —	$ 9
Fixed income securities:				
U.S. government issues	—	47	—	47
Corporate issues	—	227	—	227
International issues	—	35	—	35
Municipal issues	—	9	—	9
Mutual funds:				
U.S. equity securities	162	—	—	162
International equity securities	64	—	—	64
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts: real estate	—	—	—	24
Partnership/closely held investments:				
International equity securities	—	—	—	73
Real estate	—	—	—	6
Total	$ 226	$ 327	$ —	$ 656

The following table discloses by level within the fair value hierarchy (see Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2024 at fair value (dollars in millions):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 8	$ —	$ 8
Fixed income securities:				
U.S. government issues	—	37	—	37
Corporate issues	—	213	—	213
International issues	—	33	—	33
Municipal issues	—	11	—	11
Mutual funds:				
U.S. equity securities	160	—	—	160
International equity securities	63	—	—	63
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts: real estate	—	—	—	24
Partnership/closely held investments:				
International equity securities	—	—	—	52
Real estate	—	—	—	7
Total	$ 223	$ 302	$ —	$ 608

The fair value of other postretirement plan assets invested in debt and equity securities was based primarily on market prices. The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. For investment securities for which market prices are not readily available, the investment manager determines fair value based upon other inputs (including valuations of securities comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2025 and 2024.

The fair value of other postretirement plan assets was determined to be $75 million as of December 31, 2025 and $67 million as of December 31, 2024. The assets consist of a balanced index mutual fund, which is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and international equity and fixed income securities. This mutual fund is classified as Level 1 in the fair value hierarchy (see Note 18 for a description of the fair value hierarchy).

401(k) Plans and Executive Deferral Plan

Avista Utilities has a salary deferral 401(k) plan that is a defined contribution plan and covers substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The Company matches a portion of the salary deferred by each participant according to the schedule in the respective plan.

Employer matching contributions were as follows for the years ended December 31 (dollars in millions):

	2025	2024	2023
Employer 401(k) matching contributions	$ 18	$ 16	$ 15

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust.

There were deferred compensation assets included in other property and investments—net and corresponding deferred compensation liabilities included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in millions):

	2025	2024
Deferred compensation assets and liabilities	$ 9	$ 9

NOTE 13. ACCOUNTING FOR INCOME TAXES

Income Tax Expense

Income tax expense consisted of the following for the years ended December 31 (dollars in millions):

	2025	2024	2023
Current income tax expense:			
Federal	$ 20	$ 5	$ 1
State	2	3	2
Total current income tax expense	22	8	3
Deferred income tax expense (benefit):			
Federal	2	(5)	(37)
Total deferred income tax expense (benefit)	2	(5)	(37)
Total income tax expense (benefit)	$ 24	$ 3	$ (34)

A reconciliation of federal income taxes derived from the statutory federal tax rate of 21 percent applied to income before income taxes is as follows for the years ended December 31 (dollars in millions):

	2025		2024		2023	
Income from continuing operations before income tax expense (benefit)	$ 217	N/A	$ 183	N/A	$ 137	N/A
U.S. federal statutory tax rate	46	21.0%	38	21.0%	29	21.0%
State income taxes—net of federal income tax effect (1)	1	0.5	2	0.9	2	1.5
Research and development tax credits	(1)	(0.5)	(1)	(0.6)	(3)	(1.7)
Other adjustments:						
Flow through related to deduction of meters and mixed service costs (2)	(7)	(3.2)	(23)	(12.4)	(48)	(34.9)
Excess deferred tax amortization	(11)	(4.9)	(11)	(6.0)	(12)	(8.9)
CARES Act tax benefit amortization	(2)	(0.9)	(1)	(0.6)	(1)	(0.7)
Other	(2)	(0.9)	(1)	(0.8)	(1)	(0.7)
Total other adjustments	(22)	(9.9)	(36)	(19.8)	(62)	(45.2)
Effective tax rate	$ 24	11.1%	$ 3	1.5%	$ (34)	(24.4)%

(1) State taxes in Oregon made up greater than 50 percent of the tax effect in this category.

(2) The Company's general rate cases included approval of base rate increases, offset by tax customer credits. As the tax customer credits are returned to customers, this results in a decrease to income tax expense due to flowing through the benefits related to meters and mixed service costs. Once these tax customer credits have been applied to customers and are exhausted, income tax expense will increase.

In July 2025, OBBB was signed into law, which includes significant changes to the U.S. tax code and related laws. The Company has evaluated the potential impact of OBBB on our consolidated financial statements in accordance with ASC 740 and, as of December 31, 2025, has determined the impact to the effective tax rate is not material.

Cash Paid for Income Taxes

Income taxes paid (net of refunds) consisted of the following for the years ended December 31 (dollars in millions):

	2025	2024	2023
Federal	$ 26	$ 9	$ —
State	2	2	2
Total income taxes paid (net of refunds)	$ 28	$ 11	$ 2

State income taxes paid (net of refunds) exceeded 5 percent of total income taxes paid (net of refunds) in the following jurisdictions for the years ended December 31 (dollars in millions):

	2025	2024	2023
Alaska	*	$ 1	$ 1
Oregon	*	1	1

**Jurisdiction below the threshold for the period presented.*

Deferred Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards.

The total net deferred income tax liability consisted of the following as of December 31 (dollars in millions):

	2025	2024
Deferred income tax assets:		
Regulatory liabilities	$ 194	$ 194
Tax credits and net operating loss carryforwards	29	36
Provisions for pensions	14	16
Other	56	49
Total gross deferred income tax assets	293	295
Valuation allowances for deferred tax assets	(8)	(8)
Total deferred income tax assets after valuation allowances	285	287
Deferred income tax liabilities:		
Utility property, plant, and equipment	780	759
Regulatory assets	255	252
Other	31	27
Total gross deferred income tax liabilities	1,066	1,038
Uncertain tax benefits for deferred tax liabilities	(3)	—
Total deferred income tax liabilities	1,063	1,038
Net long-term deferred income tax liability	$ 778	$ 751

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

As of December 31, 2025, the Company had $22 million of state tax credit carryforwards. Of the total amount, the Company believes that it is more likely than not that it will only be able to utilize $14 million of the state tax credits. As such, the Company has recorded a valuation allowance of $8 million against the state tax credit carryforwards and reflected the net amount of $14 million as an asset as of December 31, 2025. State tax credits expire from 2026 to 2039.

Uncertain Tax Positions

The Company recognizes tax positions that meet the more-likely-than-not threshold as the largest amount of the tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a tax authority that has full knowledge of all relevant information.

The change in unrecognized tax benefits is as follows (dollars in millions):

	2025	2024	2023
Unrecognized tax benefits at January 1	$ 1	$ —	$ —
Gross increases—tax positions in prior period	2	—	—
Gross increases—tax positions in current period	1	1	—
Unrecognized tax benefits at December 31	$ 4	$ 1	$ —

The Company's unrecognized tax benefits include approximately $1 million related to tax positions as of December 31, 2025 and 2024 that, if recognized, would impact the annual effective tax rate.

Status of Internal Revenue Service (IRS) and State Examinations

The Company and its eligible subsidiaries file consolidated federal income tax returns. All tax years after 2021 are open for an IRS tax examination.

The Company files state income tax returns in certain jurisdictions, including Idaho, Oregon, Montana and Alaska. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis.

All tax years after 2021 are open for examination in Idaho, Oregon, Montana and Alaska.

The Company believes open tax years for federal or state income taxes will not result in adjustments that would be significant to the consolidated financial statements.

NOTE 14. ENERGY PURCHASE CONTRACTS

The discussion below only relates to Avista Utilities. The sole energy purchase contract at AEL&P is a PPA for the Snettisham Hydroelectric Project and it is accounted for as a lease. AEL&P does not have any other significant operating agreements or contractual obligations. See Note 5 for further discussion of the Snettisham PPA.

Avista Utilities has various agreements for the purchase or exchange of electric energy (including transmission), as well as contracts for the purchase of natural gas for resale and fuel for thermal generation (including transportation). The remaining term of the contracts ranges from one month to twenty-five years.

Total fixed and variable costs for power purchased (including transmission), natural gas purchased, fuel for generation and other fuel costs (including transportation), which are included in utility resource costs in the Consolidated Statements of Income, were as follows for the years ended December 31 (dollars in millions):

	2025	2024	2023
Power and natural gas resources	$ 520	$ 548	$ 607

The following table details Avista Utilities' future fixed contractual commitments for power and natural gas resources (dollars in millions):

	2026	2027	2028	2029	2030	Thereafter	Total
Power resources	$ 335	$ 268	$ 249	$ 234	$ 230	$ 2,509	$ 3,825
Natural gas resources	106	77	142	48	43	156	572
Total	$ 441	$ 345	$ 391	$ 282	$ 273	$ 2,665	$ 4,397

These energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail electric and natural gas customers' energy requirements, including contracts entered into for resource optimization. These costs are recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

The future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with PUDs to purchase portions of the output of certain generating facilities. Although the Company has no investment in the PUD generating facilities, the contracts obligate the Company to pay certain minimum amounts whether or not the facilities are operating. The cost of power purchased under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Consolidated Statements of Income. The contractual amounts included above consist of amounts in respect of the PUDs' existing debt service cost. The fixed minimum amounts payable by the Company under each contract with a PUD includes an amount that is the same percentage of the PUD's total debt service requirements on its revenue bonds issued to finance the related generating facility as the Company's percentage entitlement to the output of that facility. The total portion of the PUDs' future debt service requirements so allocable to the Company as of December 31, 2025 (principal and interest) was $264 million.

In addition, Avista Utilities has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. The expenses associated with these agreements are reflected in other operating expenses in the Consolidated Statements of Income.

The following table details future contractual commitments under these agreements (dollars in millions):

	2026	2027	2028	2029	2030	Thereafter	Total
Contractual obligations	$ 19	$ 20	$ 20	$ 21	$ 21	$ 163	$ 264

NOTE 15. SHORT-TERM BORROWINGS

Avista Corp.

Lines of Credit

Avista Corp. has a committed line of credit in the total amount of $500 million with an expiration date of June 2029. The Company may request that the lenders extend their commitments for an additional one-year period (subject to customary conditions). The committed line of credit is secured by non-transferable first mortgage bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Balances outstanding and interest rates on borrowings (excluding letters of credit) under the Company's revolving committed line of credit were as follows as of December 31 (dollars in millions):

	2025	2024
Balance outstanding at end of period	$ 385	$ 342
Letters of credit balance outstanding at end of period	5	5
Average interest rate at end of period	4.84%	5.52%

As of December 31, 2025 and 2024, the borrowings outstanding under Avista Corp.'s committed lines of credit were classified as short-term borrowings on the Consolidated Balance Sheets.

Letter of Credit Facility

Avista Corp. has a letter of credit agreement in the aggregate amount of $50 million. Either party may terminate the agreement at any time.

The Company had $14 million and $12 million in letters of credit outstanding under this agreement as of December 31, 2025 and December 31, 2024, respectively. Letters of credit are not reflected on the Consolidated Balance Sheets. If a letter of credit were drawn upon by the holder, we would have an immediate obligation to reimburse the bank that issued that letter.

Covenants and Default Provisions

The short-term borrowing agreements contain customary covenants and default provisions, including a change in control (as defined in the agreements). The events of default under each of the credit facilities also include a cross default from other indebtedness (as defined) and in one case other obligations. The committed line of credit also includes a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2025, the Company complied with this covenant.

AEL&P

AEL&P has a committed line of credit in the amount of $25 million that expires in June 2028. The committed line of credit is secured by non-transferable first mortgage bonds of AEL&P issued to the agent bank that would only become due and payable in the event, and then only to the extent, that AEL&P defaults on its obligations under the committed line of credit.

Balances outstanding and interest rates on borrowings under AEL&P's revolving committed line of credit were as follows as of December 31 (dollars in millions):

	2025	2024
Balance outstanding at end of period	$ 3	$ 12
Average interest rate at end of period	5.33%	6.13%

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt at AEL&P" to "consolidated total capitalization at AEL&P," including the impact of the Snettisham bonds to be greater than 67.5 percent at any time. As of December 31, 2025, AEL&P complied with this covenant.

NOTE 16. LONG-TERM DEBT

The following details long-term debt outstanding as of December 31 (dollars in millions):

Maturity Year	Description	Interest Rate	2025	2024
Avista Corp. Secured Long-Term Debt				
2028	Secured Medium-Term Notes	6.37%	$ 25	$ 25
2032	Secured Pollution Control Bonds	3.88%	67	67
2034	Secured Pollution Control Bonds	3.88%	17	17
2035	First Mortgage Bonds	6.25%	150	150
2037	First Mortgage Bonds	5.70%	150	150
2040	First Mortgage Bonds	5.55%	35	35
2041	First Mortgage Bonds	4.45%	85	85
2044	First Mortgage Bonds	4.11%	60	60
2045	First Mortgage Bonds	4.37%	100	100
2047	First Mortgage Bonds	4.23%	80	80
2047	First Mortgage Bonds	3.91%	90	90
2048	First Mortgage Bonds	4.35%	375	375
2049	First Mortgage Bonds	3.43%	180	180
2050	First Mortgage Bonds	3.07%	165	165
2051	First Mortgage Bonds	3.54%	175	175
2051	First Mortgage Bonds	2.90%	140	140
2052	First Mortgage Bonds	4.00%	400	400
2053	First Mortgage Bonds	5.66%	250	250
2055	First Mortgage Bonds [(1)]	6.18%	120	—
	Total Avista Corp. secured long-term debt		2,664	2,544
Alaska Electric Light and Power Company Secured Long-Term Debt				
2030	Secured Term Loan [(2)]	5.49%	20	—
2044	First Mortgage Bonds	4.54%	75	75
	Total secured long-term debt		2,759	2,619
Alaska Energy and Resources Company Unsecured Long-Term Debt				
2029	Unsecured Term Loan	5.92%	15	15
	Total secured and unsecured long-term debt		2,774	2,634
Other Long-Term Debt Components				
	Unamortized debt discount		(1)	(1)
	Unamortized long-term debt issuance costs		(19)	(19)
	Total long-term debt		$ 2,754	$ 2,614

(1) In July 2025, the Company issued and sold $120 million of 6.18 percent first mortgage bonds due in 2055 with institutional investors in the private placement market. The net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under the Company's committed line of credit.

(2) In July 2025, AEL&P entered into a term loan agreement in the amount of $20 million with an interest rate of 5.49 percent and a maturity date of July 2030. AEL&P borrowed the entire $20 million available under the agreement, and used the net proceeds to repay borrowings outstanding under AEL&P's committed line of credit, as well as fund capital expenditures. The term loan is secured under the first mortgage bonds issued to the agent bank that would become due and payable in the event, and then only to the extent, that AEL&P defaults on its obligations under the term loan. The term loan contains customary covenants and default provisions including a covenant which does not permit the ratio of "Consolidated Total Debt to Consolidated Total Capitalization" to be greater than 67.5 percent at any time. As of December 31, 2025, AEL&P complied with this covenant.

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 17) (dollars in millions):

	2026	2027	2028	2029	2030	Thereafter	Total
Debt maturities	$ —	$ —	$ 25	$ 15	$ 20	$ 2,766	$ 2,826

Substantially all of Avista Utilities' and AEL&P's owned properties are subject to the lien of their respective mortgage indentures. Under the Mortgages and Deeds of Trust (Mortgages) securing their first mortgage bonds (including secured medium-term notes), Avista Utilities and AEL&P may each issue additional first mortgage bonds under their specific mortgage in an aggregate principal amount equal to the sum of:

- 66-2/3 percent of the cost or fair value to the Company (whichever is lower) of property additions of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- an equal principal amount of retired first mortgage bonds of that entity which have not previously been made the basis of any application under that entity's Mortgage, or
- deposit of cash.

Avista Utilities and AEL&P may not individually issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the particular entity issuing the bonds has "net earnings" (as defined in that entity's Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the first mortgage bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2025, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.8 billion by Avista Corp. in an aggregate principal amount of additional first mortgage bonds and $41 million by AEL&P, at an assumed interest rate of 8 percent in each case.

NOTE 17. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $52 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50 million of Preferred Trust Securities. The distribution rate on the Preferred Trust Securities is three-month CME Term SOFR plus 1.137 percent.

The distribution rates paid were as follows during the years ended December 31:

	2025	2024	2023
Low distribution rate	4.93%	5.64%	5.64%
High distribution rate	5.64%	6.51%	6.55%
Distribution rate at the end of the year	4.93%	5.64%	6.51%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $2 million of Common Trust Securities to the Company. These Preferred Trust Securities may be redeemed at the option of Avista Capital II at any time and mature on June 1, 2037. In December 2000, the Company purchased $10 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. The Company does not include these capital trusts in its consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $52 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Consolidated Balance Sheets. Interest expense to affiliated trusts in the Consolidated Statements of Income represents interest expense on these debentures.

NOTE 18. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings as shown on the Consolidated Balance Sheets are reasonable estimates of their fair values. The carrying values of long-term debt (including current portion and finance leases), and long-term debt to affiliated trusts as shown on the Consolidated Balance Sheets may be different from the estimated fair value. See below for the estimated fair value of long-term debt and long-term debt to affiliated trusts.

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to fair values derived from unobservable inputs (Level 3 measurements).

The three levels of the fair value hierarchy are defined as follows:

Level 1—Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, but which are either directly or indirectly observable as of the reporting date. Level 2 includes financial instruments valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3—Pricing inputs include significant inputs generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Consolidated Balance Sheets as of December 31 (dollars in millions):

	2025		2024	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 1,100	$ 953	$ 1,100	$ 938
Long-term debt (Level 3)	1,674	1,326	1,534	1,163
Snettisham finance lease obligation (Level 3)	36	33	39	35
Long-term debt to affiliated trusts (Level 3)	52	46	52	47

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of market prices of 58.88 to 108.35 percent of the principal amount, where 100.00 percent represents the carrying value recorded on the Consolidated Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds. Due to the unique nature of the Snettisham finance lease obligation, the estimated fair value of these items was determined based on a discounted cash flow model using available market information. The Snettisham finance lease obligation fair value is determined using the Morgan Markets A Ex-Fin discount rate as published on December 31, 2025.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2025 at fair value on a recurring basis (dollars in millions):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting [1]	Total
December 31, 2025					
Assets:					
Energy commodity derivatives	$ —	$ 17	$ —	$ (9)	$ 8
Equity investments [3]	—	—	49	—	49
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities [3]	2	—	—	—	2
Equity securities [3]	7	—	—	—	7
Total	$ 9	$ 17	$ 49	$ (9)	$ 66
Liabilities:					
Energy commodity derivatives [2]	$ —	$ 37	$ 10	$ (19)	$ 28
Total	$ —	$ 37	$ 10	$ (19)	$ 28

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2024 at fair value on a recurring basis (dollars in millions):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting [1]	Total
December 31, 2024					
Assets:					
Energy commodity derivatives	$ —	$ 23	$ —	$ (13)	$ 10
Interest rate swap derivatives	—	1	—	—	1
Equity investments [3]	—	—	53	—	53
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities [3]	2	—	—	—	2
Equity securities [3]	7	—	—	—	7
Total	$ 9	$ 24	$ 53	$ (13)	$ 73
Liabilities:					
Energy commodity derivatives [2]	$ —	$ 61	$ 3	$ (37)	$ 27
Total	$ —	$ 61	$ 3	$ (37)	$ 27

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against payables and receivables for cash collateral held or placed with these same counterparties.

(2) The Level 3 energy commodity derivative balances are associated with a natural gas exchange agreement.

(3) Included in other property and investments-net and other non-current assets on the Consolidated Balance Sheets.

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 8 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of energy commodity derivative instruments included in Level 2. Electric derivative valuations are performed using market quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange pricing for similar instruments, adjusted for basin differences, using market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets.

Level 3 Fair Value

Natural Gas Exchange Agreement

For the natural gas commodity exchange agreement, the Company uses the same Level 2 market quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions are not highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2025 (dollars in millions, except mmBTU amounts):

	Fair Value (Net) at December 31, 2025		Valuation Technique	Unobservable Input	Range
Natural gas exchange	$	(10)	Internally derived	Forward purchase prices	$1.33–$3.25/mmBTU
			weighted-average		$2.46 Weighted-Average
			cost of gas	Forward sales prices	$1.60–$8.00/mmBTU
					$4.66 Weighted-Average
				Purchase volumes	270,000–310,000 mmBTUs
				Sales volumes	75,000–310,000 mmBTUs

The valuation methods, significant inputs and resulting fair values described above were developed by the Company and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

Equity Investments

The Company has two equity investments measured at fair value on a recurring basis. For one investment, fair value is determined using a market approach, starting with enterprise values from recent market transaction data for comparable companies with similar equity instruments. The market transaction data was used to estimate an enterprise value of the underlying investment and that value was allocated to the various classes of equity via an option pricing model and a waterfall approach. The selection of appropriate comparable companies and the expected time to a liquidation event requires management judgment. The significant assumptions in the analysis include the comparable market transactions and related enterprise values and time to liquidity event. In the event there were relevant market transactions for the same or similar securities of the subject company or there were a reasonable possibility of a transaction occurring, these transactions would be utilized as an input to the valuation with a probability weight applied to the valuation.

For the second investment, the fair value is determined using an income approach utilizing a discounted cash flow model. The model is based on income statement forecasts from the underlying company to determine cash flows for the period of ownership. The model then utilizes market multiples from publicly traded comparable companies in similar industries and projects to estimate the terminal fair value. The market multiples are reduced to reflect the difference in the life cycle between the publicly traded comparable companies and the start-up nature of the investment company. The selection of appropriate comparable companies, market multiples and the reduction to those market multiples requires management judgment. The significant assumptions in the model include the discount rate representing the risk associated with the investment, market multiples and the related reduction to those multiples, revenue forecasts, and the estimated terminal date for the investment. In the event there are relevant market transactions for the same or similar securities of the subject company or there is a reasonable possibility of a transaction occurring, those transactions are used to determine the fair value of Avista Corp.'s investment under a market approach instead of utilizing a discounted cash flow model. The market transactions are considered Level 3 inputs because they are not publicly available observable transactions.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 equity investments as of December 31, 2025 (dollars in millions):

	Fair Value (Net) at December 31, 2025	Valuation Technique	Unobservable Input	Range
Equity investments	$ 49	Market approach	Comparable enterprise values	$130–$389 $246–Average
			Time to liquidity event	2 years
		Discounted cash flows	Revenue market multiples	0.75x–5.05x Revenue 3.27x Average
			Market multiple exit reduction	68%
			Discount rate	20%
			Annual revenues	$12–$208
			Terminal date	2031

There were no transfers into or out of Level 3 fair value measurements during the period. The following table presents activity for assets and liabilities measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31 (dollars in millions):

	Natural Gas Exchange Agreement	Equity Investments	Total
2025:			
Balance as of January 1, 2025	$ (3)	$ 53	$ 50
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets	(5)	—	(5)
Recognized in net income	(2)	(4)	(6)
Ending balance as of December 31, 2025	$ (10)	$ 49	$ 39
2024:			
Balance as of January 1, 2024	$ (8)	$ 50	$ 42
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets	5	—	5
Purchases and debt conversions	—	3	3
Ending balance as of December 31, 2024	$ (3)	$ 53	$ 50
2023:			
Balance as of January 1, 2023	$ (18)	$ 54	$ 36
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets	10	—	10
Recognized in net income	—	(4)	(4)
Purchases and debt conversions	—	3	3
Other	—	(3)	(3)
Ending balance as of December 31, 2023	$ (8)	$ 50	$ 42

NOTE 19. COMMON STOCK

The payment of dividends on common stock could be limited by:

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,
- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1), and
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Utilities to maintain a capital structure of no less than 40 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC.

The requirements of the OPUC approval of the AERC acquisition are the most restrictive. Under the OPUC restriction, the amount available for dividends at December 31, 2025 was $332 million.

See the Consolidated Statements of Equity for dividends declared in the years 2023 through 2025.

The Company has 10 million authorized shares of preferred stock. The Company did not have preferred stock outstanding as of December 31, 2025 and 2024.

Common Stock Issuances

The Company issued common stock for total—net proceeds of $78 million in 2025. Most of these issuances were made through sales agency agreements under which the Company may offer and sell new shares of common stock from time-to-time through its sales agents. In 2025, 2.0 million shares were issued under these agreements.

NOTE 20. ACCUMULATED OTHER COMPREHENSIVE LOSS

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss—net of tax, was immaterial as of December 31, 2025 and December 31, 2024.

The following table details the reclassifications out of accumulated other comprehensive loss by component for the years ended December 31 (dollars in millions):

Details about Accumulated Other Comprehensive (Loss) Income Components (Affected Line Item in Statements of Income)	**Amounts Reclassified from Accumulated Other Comprehensive (Loss) Income**		
	2025	**2024**	**2023**
Amortization of defined benefit pension and postretirement benefit items			
Amortization of net prior service cost [a]	$ —	$ 1	$ (1)
Amortization of net loss [a]	31	(12)	19
Adjustment due to effects of regulation [a]	(32)	11	(16)
Total before tax [b]	(1)	—	2
Tax expense [b]	—	—	—
Net of tax [b]	$ (1)	$ —	$ 2

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 12 for additional details).

(b) Description is also the affected line item on the Consolidated Statements of Income.

NOTE 21. EARNINGS PER COMMON SHARE

The following table presents the computation of basic and diluted earnings per common share for the years ended December 31 (dollars in millions, except per share amounts, and shares in thousands):

	2025	2024	2023
Numerator:			
Net income	$ 193	$ 180	$ 171
Denominator:			
Weighted-average number of common shares outstanding—basic	80,975	78,725	76,396
Effect of dilutive securities:			
Performance and restricted stock awards	76	95	100
Weighted-average number of common shares outstanding—diluted	81,051	78,820	76,495
Earnings per common share: (1)			
Basic	$ 2.38	$ 2.29	$ 2.24
Diluted	$ 2.38	$ 2.29	$ 2.24

(1) Per share amounts may not recalculate due to rounding of numerator and denominator amounts within this table.

There were no shares excluded from the calculation because they were antidilutive.

NOTE 22. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company will vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the outcome of any matter because litigation and other contested proceedings are subject to numerous uncertainties. For matters affecting Avista Utilities' or AEL&P's operations, the Company intends to seek, to the extent appropriate, recovery of costs through the ratemaking process.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the IBEW represents 35 percent of all Avista Utilities' employees. The Company's largest represented group, representing approximately 90 percent of Avista Utilities' bargaining unit employees in Washington, Idaho and Montana, are covered under a four-year agreement which expires in 2029.

In April 2025, the Company's System Operators voted to unionize, and the National Labor Relations Board certified the IBEW Local 77 as their exclusive collective bargaining representative. We are in the process of negotiating a separate contract with the IBEW for the System Operator group, which is comprised of approximately 20 employees.

Boyds Fire (State of Washington Department of Natural Resources v. Avista)

In August 2019, the Company was served with a complaint, captioned "State of Washington Department of Natural Resources v. Avista Corporation," seeking recovery of up to $4 million for fire suppression and investigation costs and related expenses incurred in connection with a wildfire (known as the "Boyds Fire") that occurred in Ferry County, Washington, in August 2018. Additional lawsuits were subsequently filed by private landowners seeking $1 million in property damages as well as potential non-economic damages, and holders of insurance subrogation claims seeking recovery of $2 million in insurance proceeds purportedly paid to their insureds.

In June 2025, the Company settled with a single plaintiff which only named the Company as a defendant for less than $0.1 million. Additionally, the Company, along with its independent vegetation management contractors Asplundh Tree Company and CN Utility Consulting, reached agreements to settle all claims included in the remaining lawsuits for $3 million. None of the settlements in these cases were the responsibility of the Company, but rather the responsibility was split between Asplundh Tree Company and CN Utility Consulting.

Labor Day 2020 Windstorm/Babb Road Fire

In September 2020, a severe windstorm occurred in eastern Washington and northern Idaho. The extreme weather event resulted in customer outages and multiple wildfires in the region, including the Babb Road Fire, which occurred near the town of Malden, Washington.

Eleven lawsuits were filed in connection with the Babb Road Fire. CN Utility Consulting, which performs vegetation management services as an independent contractor to the Company, was also named as defendants in each of the lawsuits. The lawsuits included six subrogation actions filed by 51 insurance companies and five actions on behalf of 128 individual plaintiffs.

In April and May 2025, the Company and CN Utility Consulting reached agreements to settle all claims included in the lawsuits. The total settlement paid was $27 million, of which the Company paid $21 million and CN Utility Consulting was responsible for $6 million. An order dismissing all cases was entered by the Court in September 2025. The Company received insurance proceeds for the settlement amounts paid, resulting in no impact on net income.

Orofino Fire

In August 2023, a fire started in windy conditions near Orofino, Idaho, burning 53 acres and seven primary residences, as well as several outbuildings. The Idaho Department of Lands investigated and has issued a report in which it concluded the fire was caused by an electrical fault igniting three separate spots which then spread uphill. The Company has a distribution line in the area near the ignition point. The Company has to date found no evidence suggesting negligence on its part. Except for three minor claims for damage to personal property which were resolved, the Company has not, at this time, received any claims in connection with the fire. The Company will vigorously defend itself in the event any additional claims are asserted; however, at this time, it is unable to estimate the likelihood of an adverse outcome or the amount or range of a potential loss in the event of an adverse outcome.

Colstrip

Colstrip Owners Arbitration and Litigation

Prior to January 1, 2026, Colstrip Units 3 & 4 were owned by the Company, PacifiCorp, Portland General Electric (PGE), and Puget Sound Energy (PSE) (collectively, the "Western Co-Owners"), as well as NorthWestern and Talen Montana, LLC (Talen), as tenants in common under an Ownership and Operating Agreement, dated May 6, 1981, as amended (O&O Agreement), in the percentages set forth below:

Co-Owner	Unit 3	Unit 4
Avista	15%	15%
PacifiCorp	10%	10%
PGE	20%	20%
PSE	25%	25%
NorthWestern	—	30%
Talen	30%	—

Colstrip Units 1 & 2, owned by PSE and Talen, were shut down in 2020 and are in the process of being decommissioned. The co-owners of Units 3 & 4 also own undivided interests in facilities common to both Units 3 & 4, as well as in certain facilities common to all four Colstrip units.

The Washington Clean Energy Transformation Act (CETA), among other things, imposed deadlines by which each electric utility must eliminate from its electricity rates in Washington the costs and benefits associated with coal-fired resources, such as Colstrip. The practical impact of CETA was that electricity from such resources, including Colstrip, could no longer be delivered to Washington retail customers after 2025.

Agreement Between Avista and NorthWestern

In January 2023, the Company entered into an agreement with NorthWestern under which, subject to the terms and conditions specified in the agreement, the Company would transfer its 15 percent ownership in Colstrip Units 3 & 4 to NorthWestern. There was no monetary exchange included in the transaction. The transaction closed at midnight on January 1, 2026.

Under the agreement, the Company was obligated through the close of the transaction to pay its share of (i) operating expenses, (ii) capital expenditures, but not in excess of the portion allocable pro rata to the portion of useful life (through 2030) expired through the close of the transaction, and (iii) site remediation expenses except certain costs relating to post closing activities. In addition, under the agreement, the Company retained its voting rights with respect to decisions relating to remediation.

The Company retained its interest in the Colstrip transmission line between Colstrip, Montana to Townsend, Montana, which is excluded from the transaction.

Agreement Between PSE and NorthWestern

In July 2024, PSE entered into an agreement with NorthWestern under which, PSE will transfer its 25 percent ownership in Colstrip Units 3 & 4 to NorthWestern. There was no monetary exchange included in the transaction. The transaction closed at midnight on January 1, 2026.

Burnett et al. v. Talen et al.

Multiple property owners initiated a legal proceeding (titled Burnett et al. v. Talen et al.) in the Montana District Court for Rosebud County against Talen, PSE, PacifiCorp, PGE, Avista Corp., NorthWestern, and Westmoreland Rosebud Mining. The plaintiffs alleged the failure to contain coal dust in connection with the operation of Colstrip, and was seeking unspecified damages. In March 2025, the parties reached an agreement to settle all claims in the matter for $1 million, with the majority of that amount being paid through insurance proceeds and the remainder by entities other than the owners of Colstrip.

Westmoreland Mine Permits

Two lawsuits have been commenced by the Montana Environmental Information Center and others, challenging certain permits relating to the operation of the Westmoreland Rosebud Mine, which provides coal to Colstrip. In the first, the Montana District Court for Rosebud County issued an order vacating a permit for one area of the mine, which decision was subsequently upheld by the Montana Supreme Court. In the second, the Montana Federal District Court vacated a decision by the federal Office of Surface Mining Reclamation and Enforcement, a branch of the United States Department of the Interior, approving expansion of the mine into a new area, pending further analysis of potential environmental impact. An initial appeal of that decision to the Ninth Circuit was dismissed for lack of jurisdiction, pending further proceedings before the Department of the Interior. Avista Corp. is not a party to either of these proceedings, and is no longer impacted by the outcome of these proceedings, given its transfer of Colstrip to NorthWestern.

Rathdrum, Idaho Natural Gas Incident

In October 2021, there was an incident in Rathdrum, Idaho involving the Company's natural gas infrastructure. The incident occurred after a third party damaged those facilities during excavation work. The incident resulted in a fire which destroyed one residence and resulted in minor injuries to the occupants. In January 2023, the Company was served with a lawsuit filed in the District Court of Kootenai County, Idaho by one property owner, seeking unspecified damages. In February 2024, the Company received a second lawsuit filed by the owners of the adjacent property, seeking damages for personal injury and emotional distress from having witnessed the incident. The Company continues to vigorously defend itself in the legal proceedings; however, at this time, the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Complaint of Consumers for Independent Regional Transmission Planning for All FERC-Jurisdictional Transmission Facilities at 100kV and Above

In December 2024, the Company received notice of a complaint filed with the FERC by Consumers for Independent Regional Transmission Planning against all FERC-jurisdictional Transmission providers with local planning tariffs utilizing facilities at 100 kV and above, which includes the Company. The complaint alleges that the local transmission planning process allows individual transmission owners to plan FERC-jurisdictional transmission facilities without regard to whether that planning is the more efficient or cost-effective project for the interconnected grid and cost effective for customers. The Company intends to vigorously defend itself in this action; however, at this time, the Company is unable to predict the likelihood of an adverse outcome or estimate a range of potential loss in the event of such an outcome.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes any liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

The Company routinely assesses, based on studies, expert analysis and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred.

The Company has potential liabilities under the Endangered Species Act and similar state statutes for species of fish, plants and wildlife that have either already been added to the endangered species list, listed as "threatened" or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to these issues.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. In addition, the Company holds additional non-hydro water rights. The States of Montana and Idaho are each conducting general adjudications of water rights in areas that include the Company's facilities in these states. Claims within the Clark Fork River basin and the Spokane River basin could adversely affect the energy production of the Company's hydroelectric facilities. The Company is and will continue to be a participant in the adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time. The Company will continue to seek recovery, through the ratemaking process, of all costs related to this issue.

NOTE 23. REGULATORY MATTERS

Regulatory Assets and Liabilities

The following table presents the Company's regulatory assets and liabilities as of December 31, 2025 (dollars in millions):

		Receiving Regulatory Treatment			2025		2024	
	Remaining Amortization Period	Earning a Return (1)	Not Earning a Return	Expected Recovery or Refund (2)	Current	Non-current	Current	Non-current
Regulatory Assets:								
Deferred income tax	(3) (16)	$ —	$ 246	$ —	$ —	$ 246	$ —	$ 246
Pensions and other postretirement benefit plans	(4)	—	73	—	1	72	—	106
Climate Commitment Act	(14)	24	—	—	24	—	50	—
Energy commodity derivatives	(5)	—	30	—	18	12	27	14
Unamortized debt repurchase costs	(6)	5	—	—	—	5	—	5
Settlement with Coeur d'Alene Tribe	2059	34	—	—	—	34	—	36
Demand side management programs	(3)	—	57	—	—	57	—	38
Decoupling surcharge	2027	48	—	—	27	21	12	12
Utility plant abandoned	(7)	33	—	—	2	31	4	38
Interest rate swaps	(8)	165	—	—	—	165	—	172
Deferred power costs	(3)	88	—	—	17	71	9	27
AFUDC above FERC allowed rate	(11)	51	—	—	—	51	—	49
COVID-19 deferrals	(12)	—	—	—	—	—	—	12
Advanced meter infrastructure	(13)	23	—	—	3	20	—	26
Colstrip	(17)	33	—	—	2	31	15	10
Wildfire resiliency	(18)	8	18	—	9	17	10	13
Insurance deferrals	(18)	9	7	—	8	8	4	7
Other regulatory assets	(3)	21	22	11	24	30	6	36
Total regulatory assets		$ 542	$ 453	$ 11	$ 135	$ 871	$ 137	$ 847
Regulatory Liabilities:								
Deferred natural gas costs	(3)	$ 33	$ —	$ —	$ 33	$ —	$ 25	$ —
Deferred power costs	(3)	7	—	—	7	—	8	6
Utility plant retirement costs	(9)	468	—	—	—	468	—	448
Excess deferred income taxes	(10)	279	—	—	13	266	14	279
Other income tax related liabilities	(3) (15)	30	28	—	7	51	5	59
Climate Commitment Act	(14)	33	1	—	34	—	44	—
Interest rate swaps	(8)	22	—	1	—	23	—	24
Decoupling rebate	2027	4	—	—	1	3	4	—
Provision for rate refund	(3)	13	—		13	—	—	—
COVID-19 deferrals	(12)	—	—	—	—	—	—	10
Other regulatory liabilities	(3)	8	13	4	18	7	8	8
Total regulatory liabilities		$ 897	$ 42	$ 5	$ 126	$ 818	$ 108	$ 834

(1) Earning a return includes either interest on the regulatory asset/liability or a return on the investment as a component of rate base at the allowed rate of return.

(2) Expected recovery is pending regulatory treatment including regulatory assets and liabilities with prior regulatory precedence.

(3) Remaining amortization period varies depending on timing of underlying transactions.

(4) As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency.

(5) The WUTC and the IPUC issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and losses result in adjustments to retail rates through PGAs, the ERM in Washington, the PCA mechanism in Idaho and periodic general rates cases. The resulting regulatory assets associated with energy commodity derivative instruments have been concluded to be probable of recovery through future rates.

(6) Premiums paid or discounts received to repurchase debt are amortized over the remaining life of the original debt repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. These costs are recovered through retail rates as a component of interest expense.

(7) The WUTC approved recovery of AMI project costs through the 2020 general rate case settlements, including amortization of retired meters replaced through the project through 2033. The IPUC approved deferral accounting treatment for the Idaho AMI project, which will be included in a future rate case. In addition, the IPUC approved the depreciation of Colstrip through 2027, and as such the remaining depreciation after our exit of Colstrip in 2025 is included in this balance. There are additional smaller projects included in the balance the Company expects to fully recover, which have not yet been through the regulatory process.

(8) For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no impact on the income statement. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process. Settled interest rate swap derivatives which have been through a general rate case proceeding are classified as earning a return in the table above, whereas all unsettled interest rate swap derivatives and settled interest rate swap derivatives which have not been included in a general rate case are classified as expected recovery.

(9) This amount is dependent upon the cost of removal of underlying utility plant assets and the life of utility plant.

(10) This balance represents amounts due back to customers and resulted from the Tax Cuts and Jobs Act signed into law in December 2017, which changed the federal income tax rate from 35 percent to 21 percent. The Company revalued all deferred income taxes as of December 31, 2017. The Company expects the amounts for utility plant items for Avista Utilities to be returned to customers over a period of approximately 29 years. The Company expects the AEL&P amounts to be returned to customers over a period of approximately 20 years.

(11) This amount is being amortized based on the underlying utility plant assets and the life of utility plant.

(12) The WUTC, IPUC and OPUC issued accounting orders allowing the Company to defer certain costs, net of benefits, related to the COVID-19 pandemic. The Company has recorded all benefits on a gross basis as a regulatory liability to customers and all additional allowed costs are a regulatory asset. The ratemaking treatment is being determined in general rate cases in each jurisdiction.

(13) This amount represents the deferral of the depreciation expense of the Company's AMI project in Washington state. Recovery of these amounts was approved by WUTC in the 2021 general rate case order, and the asset will be amortized through 2033.

(14) Regulatory assets related to the Climate Commitment Act represent costs incurred to comply with the program. Regulatory liabilities related to the Climate Commitment Act represent proceeds from the required sale of allowances, which will be returned to customers. The Company submits filings periodically to receive approval to include these items in customer rates.

(15) The portion of this balance earning a return represents the remaining tax customer credits being returned to customers. The majority of the portion not earning a return represents investment tax credits, which have a corresponding deferred tax asset within Note 13 which is also excluded from rate base.

(16) The majority of this balance represents flow-through income tax accounting differences and the related tax gross-up which have a corresponding deferred tax liability within Note 13 which is also excluded from rate base.

(17) The majority of this balance relates to decommissioning and remediation costs, including asset retirement obligations, associated with Colstrip. The Company retained these obligations through the transfer of its ownership to NorthWestern.

(18) These balances are primarily balancing accounts, by which the WUTC and IPUC sets a base expense level, and any costs incurred above that base are deferred to be recovered from customers at a later date.

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Consolidated Balance Sheets for future prudence review and recovery or rebate through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level, availability and optimization of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices),
- retail loads, and
- sales of surplus transmission capacity.

In Washington, the ERM allows Avista Utilities to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. Under the ERM, the Company defers these differences (over the $4 million deadband and sharing bands) for future surcharge or rebate to customers.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
within +/- $0 to $4 million (deadband)	0%	100%
higher by $4 million to $10 million	50%	50%
lower by $4 million to $10 million	75%	25%
higher or lower by over $10 million	90%	10%

Total net deferred power costs under the ERM were assets of $85 million as of December 31, 2025 and $36 million as of December 31, 2024. The deferred power cost assets represent amounts due from customers, and deferred power cost liabilities represent amounts due to customers.

Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, the Company must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. Avista Utilities makes an annual filing on, or before, April 1 of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of, and audit, the ERM deferred power cost transactions for the prior calendar year. The Company received approval to recover $32 million of the ERM deferred surcharge balance over a two-year period starting July 1, 2025.

Avista Utilities has a PCA mechanism in Idaho allowing for the modification of electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista Utilities defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. The October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were liabilities of $5 million as of December 31, 2025 and $15 million as of December 31, 2024. Deferred power cost assets represent amounts due from customers and liabilities represent amounts due to customers.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities files a PGA in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. In Oregon, the Company absorbs (cost or benefit) 10 percent of the difference between actual and projected natural gas costs included in base retail rates for supply that is not hedged. Total net deferred natural gas costs were a liability of $33 million as of December 31, 2025 and $25 million as of December 31, 2024. Liability balances represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as an FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Utilities' jurisdictions, Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes and assumed "normal" kilowatt hour and therm sales, rather than being based on actual kilowatt hour and therm sales. The difference between revenues based on the number of customers and "normal" sales and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year. Only residential and certain commercial customer classes are included in decoupling mechanisms.

Washington Decoupling and Earnings Sharing

In Washington, the WUTC approved the Company's decoupling mechanisms for electric and natural gas through December 2026.

Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with remaining surcharge balance carried forward for recovery in a future period. There is no limit to the level of rebate rate adjustments. New customers added after a test period are not decoupled until included in a future test period.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations are made for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. Through the 2022 general rate cases, the Company modified its earnings test so that if the Company earns more than 0.5 percent higher than the ROR authorized by the WUTC in the multi-year rate plan, the Company will defer these excess revenues and later return them to customers.

Idaho FCA and Earnings Sharing Mechanisms

In Idaho, the IPUC approved the implementation of FCAs for electric and natural gas through March 31, 2025. A pending application would extend the mechanism through August 31, 2029.

Oregon Decoupling Mechanism

In Oregon, the Company has a decoupling mechanism for natural gas. An earnings review is conducted on an annual basis. In the annual earnings review, if the Company earns more than 100 basis points above its allowed ROE, one-third of the earnings above the 100 basis points would be deferred and later returned to customers. The earnings review is separate from the decoupling mechanism and was in place prior to decoupling.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2025 and December 31, 2024, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in millions):

	December 31, 2025	December 31, 2024
Washington		
Decoupling surcharge	$ 31	$ 18
Provision for earnings sharing rebate	$ (4)	$ —
Idaho		
Decoupling surcharge	$ 4	$ 1
Oregon		
Decoupling surcharge	$ 9	$ 1

NOTE 24. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the information reviewed by the Company's Chief Operating Decision Maker (CODM, the Company's President and Chief Executive Officer). Such information is the basis for the analysis of segment performance and the allocation of resources. Performance is evaluated based on net income (loss) and variances of actual performance from the Company's budget and/or forecast when making decisions. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Avista Utilities' business is managed based on the total regulated utility operation; therefore, it is considered one segment. AEL&P is a separate reportable business segment since it has separate financial information and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with other operating segments. The Other category, which is not a reportable segment, includes other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital. Decisions by the CODM are made in consultation with other members of management, as appropriate, and are subject to the general oversight and strategic direction of the Board of Directors.

The following table presents information for each of the Company's business segments (dollars in millions):

	Reportable Segments					
	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other Non-Reportable Segment Items	Eliminations [1]	Total
2025						
Operating revenues	$ 1,916	$ 47	1,963	$ 1	$ —	$ 1,964
Resource costs	689	2	691	—	—	691
Other operating expenses	487	17	504	5	—	509
Depreciation and amortization	277	12	289	—	—	289
Interest income	13	—	13	1	(2)	12
Interest expense [2]	147	6	153	3	(2)	154
Other segment expenses [3]	102	2	104	12	—	116
Income tax expense (benefit)	26	2	28	(4)	—	24
Net income (loss)	201	6	207	(14)	—	193
Capital expenditures [4]	553	17	570	—	—	570
2024						
Operating revenues	$ 1,887	$ 50	$ 1,937	$ 1	$ —	$ 1,938
Resource costs	794	4	798	—	—	798
Other operating expenses	426	17	443	1	—	444
Depreciation and amortization	263	11	274	—	—	274
Interest income	15	—	15	1	(2)	14
Interest expense [2]	143	6	149	3	(2)	150
Other segment expenses [3]	95	1	96	7	—	103
Income tax expense (benefit)	2	3	5	(2)	—	3
Net income (loss)	179	8	187	(7)	—	180
Capital expenditures [4]	510	23	533	—	—	533
2023						
Operating revenues	$ 1,703	$ 48	$ 1,751	$ 1	$ —	$ 1,752
Resource costs	698	4	702	—	—	702
Other operating expenses	399	15	414	3	—	417
Depreciation and amortization	254	11	265	—	—	265
Interest income	15	—	15	1	(1)	15
Interest expense [2]	137	6	143	2	(1)	144
Other segment expenses [3]	98	—	98	4	—	102
Income tax expense (benefit)	(35)	3	(32)	(2)	—	(34)
Net income (loss)	167	9	176	(5)	—	171
Capital expenditures [4]	485	14	499	0	—	499
Total Assets:						
As of December 31, 2025	$ 7,917	$ 289	$ 8,206	$ 177	$ (24)	$ 8,359
As of December 31, 2024	7,494	283	7,777	194	(30)	7,941
As of December 31, 2023	7,263	270	7,533	191	(22)	7,702

(1) Eliminations reported as interest expense and interest income represent intercompany interest. Eliminations reported as assets represent intersegment accounts receivable.

(2) Including interest expense to affiliated trusts.

(3) Other segment items include taxes other than income tax, AFUDC equity, other miscellaneous expenses, and earnings (losses) from investments.

(4) The capital expenditures for the other businesses are included in other investing activities on the Consolidated Statements of Cash Flows.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

ITEM 9A. Controls and Procedures

CONCLUSION REGARDING THE EFFECTIVENESS OF DISCLOSURE CONTROLS AND PROCEDURES

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Act) that are designed to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. With the participation of the Company's principal executive officer and principal financial officer, the Company's management evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of December 31, 2025.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company conducted an assessment of the effectiveness of the Company's internal control over financial reporting based on the framework established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company's internal control over financial reporting as of December 31, 2025 is effective at a reasonable assurance level.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2025.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in the Company's internal control over financial reporting that occurred during the Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Avista Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the "Company") as of December 31, 2025, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2025, of the Company and our report dated February 24, 2026, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 24, 2026

ITEM 9B. Other Information

During the fiscal quarter ended December 31, 2025, none of our directors or officers informed us of the adoption or termination of a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as those terms are defined in Regulation S-K, Item 408. A copy of our insider trading policy has been included as Exhibit 19 to this report.

ITEM 9C. Disclosure Regarding Foreign Jurisdictions That Prevent Inspections

Not applicable.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

The information required by this Item (other than the information regarding executive officers and the Company's Code of Business Conduct and Ethics set forth below) is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 14, 2026, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 26, 2025, relating to its Annual Meeting of Shareholders held on May 8, 2025.

Information about our Executive Officers

Name	Age	Business Experience
Heather L. Rosentrater	**48**	President, Chief Executive Officer and Director since January 2025, President and Chief Operating Officer October 2023-December 2024; Senior Vice President and Chief Operating Officer from September 2022 to October 2023; Senior Vice President, Energy Delivery and Shared Services from January 2020 to September 2022; Senior Vice President, Energy Delivery from October 2019 to December 2019; Vice President of Energy Delivery from December 2015 to October 2019; various other management and staff positions with the Company since 1996.
Kevin J. Christie	**58**	Senior Vice President, Chief Financial Officer, Treasurer and Regulatory Affairs Officer since May 2023; Senior Vice President, External Affairs and Chief Customer Officer from October 2019 to May 2023; Vice President, External Affairs and Chief Customer Officer January 2018 to October 2019; Vice President of Customer Solutions from February 2015 to January 2018; various other management and staff positions with the Company since 2005.
Bryan A. Cox	**56**	Senior Vice President, Safety and Chief People Officer since October 2023; Vice President, Safety and Chief People Officer from September 2022 to October 2023; Vice President, Safety and Human Resources from January 2020 to September 2022; Vice President, Safety and HR Shared Services from January 2018 to January 2020; various other management and staff positions with the Company since 1997.
Gregory C. Hesler	**48**	Senior Vice President, General Counsel, Corporate Secretary and Chief Ethics/Compliance Officer since September 2022; Vice President, General Counsel, Corporate Secretary and Chief Ethics/Compliance Officer from May 2020 to September 2022; Vice President, General Counsel and Chief Compliance Officer from January 2020 to May 2020; various other management and staff positions with the Company since 2015.
Wayne O. Manuel	**53**	Senior Vice President, Operations and Technology since October 2025; Vice President, Chief Information Officer and Chief Security Officer since June 2023 to September 2025; prior to employment with the Company, Senior Vice President, Chief Strategy Officer and Chief Information Officer of Valley Medical Center from 2014 to May 2023.
Jason R. Thackston	**56**	Senior Vice President, Growth, Energy Policy and External Relations since October 2025; Senior Vice President, Energy Policy and Chief Strategy Officer from January 2025 to September 2025; Senior Vice President, Chief Strategy and Clean Energy Officer September 2022 to December 2024; Senior Vice President of Energy Resources and Environmental Compliance Officer from May 2018 to September 2022; Senior Vice President of Energy Resources from January 2014 to May 2018; Vice President of Energy Resources from December 2012 to January 2014; Vice President of Customer Solutions—Avista Utilities from June 2012 to December 2012; Vice President of Energy Delivery from April 2011 to December 2012; Vice President of Finance from June 2009 to April 2011; various other management and staff positions with the Company since 1996.

Alexis G. Alexander	**43**	Vice President, Chief Information Officer and Chief Security Officer since October 2025; various other management and staff positions with the Company since 2006.
Joshua D. DiLuciano	**45**	Vice President, Energy Delivery since September 2022; various other management and staff positions with the Company since 2006.
Latisha D. Hill	**47**	Vice President, Community Affairs and Chief Customer Officer since May 2023; Vice President of Community and Economic Vitality from January 2020 to May 2023; various other management and staff positions with the Company since 2005.
Scott J. Kinney	**57**	Vice President, Energy Resources and Integrated Planning since January 2025; Vice President of Energy Resources from September 2022 to December 2024; various other management and staff positions with the Company since 1999.
Ryan L. Krasselt	**56**	Vice President, Controller and Principal Accounting Officer since October 2015; various other management and staff positions with the Company since 2001.

All of the Company's executive officers, with the exception of Alexis G. Alexander, Joshua D. DiLuciano, Scott J. Kinney and Wayne O. Manuel were officers or directors of one or more of the Company's subsidiaries in 2025. The Company's executive officers are appointed annually by the Board of Directors.

The Company has adopted a Code of Conduct for directors, officers (including the principal executive officer, principal financial officer and principal accounting officer), and employees. The Code of Conduct is available on the Company's website at www.avistacorp.com and will be provided to any shareholder without charge upon written request to:

Avista Corp.
General Counsel
P.O. Box 3727 MSC-10
Spokane, Washington 99220-3727

Any changes to or waivers for executive officers and directors of the Company's Code of Conduct will be posted on the Company's website.

ITEM 11. Executive Compensation

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 14, 2026, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 26, 2025, relating to its Annual Meeting of Shareholders held on May 8, 2025.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

(a) Security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities):

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities) has been omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 14, 2026, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 26, 2025, relating to its Annual Meeting of Shareholders held on May 8, 2025; reference also being made to Schedules 13G, as amended, on file with the SEC with respect to the Registrant's voting securities (the information contained in such schedules 13G, as amended, not being incorporated herein by reference).

(b) Security ownership of management:

The information required by this Item regarding the security ownership of management is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 14, 2026, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 26, 2025, relating to its Annual Meeting of Shareholders held on May 8, 2025.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2025:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights [(1)]	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders [(2)]	—	$ —	153,578

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long-Term Incentive Plan. At December 31, 2025, 190,979 Restricted Share awards were outstanding. Performance and market-based share awards may be paid out at zero shares at a minimum achievement level; 309,447 shares at target level; or 618,894 shares at a maximum level. Because there is no exercise price associated with restricted shares or performance and market-based share awards, such shares are not included in the weighted-average price calculation.

(2) Includes the Long-Term Incentive Plan approved by shareholders in 1998 (amended in 2016) and the Non-Employee Director Stock Plan approved by shareholders in 1996. In February 2005, the Board of Directors elected to terminate the Non-Employee Director Stock Plan.

ITEM 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 14, 2026, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 26, 2025, relating to its Annual Meeting of Shareholders held on May 8, 2025.

ITEM 14. Principal Accounting Fees and Services

The information required by this Item is omitted pursuant to General Instruction G to Form 10-K. Such information is incorporated herein by reference as follows:

- on and after the date of filing with the SEC the Registrant's definitive Proxy Statement relating to its Annual Meeting of Shareholders scheduled to be held on May 14, 2026, from such Proxy Statement; and
- prior to such date, from the Registrant's definitive Proxy Statement, dated March 26, 2025, relating to its Annual Meeting of Shareholders held on May 8, 2025.

PART IV

ITEM 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements (Included in Part II of this report):

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income for the Years Ended December 31, 2025, 2024 and 2023

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2025, 2024 and 2023

Consolidated Balance Sheets as of December 31, 2025, and 2024

Consolidated Statements of Cash Flows for the Years Ended December 31, 2025, 2024 and 2023

Consolidated Statements of Equity for the Years Ended December 31, 2025, 2024 and 2023

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on the following page. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K pursuant to Item 15(b).

EXHIBIT INDEX

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
2.1	(with Form 8-K filed as of January 17, 2023)	2.1	Colstrip Units 3 & 4 Interests Abandonment and Acquisition Agreement, dated as of January 16, 2023, among Avista Corporation and NorthWestern Corporation.
3.1	(with June 30, 2012 Form 10-Q)	3.1	Restated Articles of Incorporation of Avista Corporation, as amended and restated June 6, 2012.
3.2	(with Form 8-K filed as of August 17, 2016)	3.2	Bylaws of Avista Corporation, as amended August 17, 2016.
4.1	2-4077	B-3	Mortgage and Deed of Trust, dated as of June 1, 1939.*
4.2	2-9812	4(c)	First Supplemental Indenture, dated as of October 1, 1952.*
4.3	2-60728	2(b)-2	Second Supplemental Indenture, dated as of May 1, 1953.*
4.4	2-13421	4(b)-3	Third Supplemental Indenture, dated as of December 1, 1955.*
4.5	2-13421	4(b)-4	Fourth Supplemental Indenture, dated as of March 15, 1967.*
4.6	2-60728	2(b)-5	Fifth Supplemental Indenture, dated as of July 1, 1957.*
4.7	2-60728	2(b)-6	Sixth Supplemental Indenture, dated as of January 1, 1958.*
4.8	2-60728	2(b)-7	Seventh Supplemental Indenture, dated as of August 1, 1958.*
4.9	2-60728	2(b)-8	Eighth Supplemental Indenture, dated as of January 1, 1959.*
4.10	2-60728	2(b)-9	Ninth Supplemental Indenture, dated as of January 1, 1960.*
4.11	2-60728	2(b)-10	Tenth Supplemental Indenture, dated as of April 1, 1964.*
4.12	2-60728	2(b)-11	Eleventh Supplemental Indenture, dated as of March 1, 1965.*
4.13	2-60728	2(b)-12	Twelfth Supplemental Indenture, dated as of May 1, 1966.*
4.14	2-60728	2(b)-13	Thirteenth Supplemental Indenture, dated as of August 1, 1966.*
4.15	2-60728	2(b)-14	Fourteenth Supplemental Indenture, dated as of April 1, 1970.*
4.16	2-60728	2(b)-15	Fifteenth Supplemental Indenture, dated as of May 1, 1973.*
4.17	2-60728	2(b)-16	Sixteenth Supplemental Indenture, dated as of February 1, 1975.*
4.18	2-60728	2(b)-17	Seventeenth Supplemental Indenture, dated as of November 1, 1976.*
4.19	2-69080	2(b)-18	Eighteenth Supplemental Indenture, dated as of June 1, 1980.*
4.20	(with 1980 Form 10-K)	4(a)-20	Nineteenth Supplemental Indenture, dated as of January 1, 1981.*
4.21	2-79571	4(a)-21	Twentieth Supplemental Indenture, dated as of August 1, 1982.*

Exhibit	Previously Filed[1] With Registration Number	As Exhibit	
4.22	(with Form 8-K dated September 20, 1983)	4(a)-22	Twenty-First Supplemental Indenture, dated as of September 1, 1983.*
4.23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.*
4.24	(with 1986 Form 10-K)	4(a)-24	Twenty-Third Supplemental Indenture, dated as of December 1, 1986.*
4.25	(with 1987 Form 10-K)	4(a)-25	Twenty-Fourth Supplemental Indenture, dated as of January 1, 1988.*
4.26	(with 1989 Form 10-K)	4(a)-26	Twenty-Fifth Supplemental Indenture, dated as of October 1, 1989.*
4.27	33-51669	4(a)-27	Twenty-Sixth Supplemental Indenture, dated as of April 1, 1993.*
4.28	(with 1993 Form 10-K)	4(a)-28	Twenty-Seventh Supplemental Indenture, dated as of January 1, 1994.
4.29	(with 2001 Form 10-K)	4(a)-29	Twenty-Eighth Supplemental Indenture, dated as of September 1, 2001.
4.30	333-82502	4(b)	Twenty-Ninth Supplemental Indenture, dated as of December 1, 2001.
4.31	(with June 30, 2002 Form 10-Q)	4(f)	Thirtieth Supplemental Indenture, dated as of May 1, 2002.
4.32	333-39551	4(b)	Thirty-First Supplemental Indenture, dated as of May 1, 2003.
4.33	(with September 30, 2003 Form 10-Q)	4(f)	Thirty-Second Supplemental Indenture, dated as of September 1, 2003.
4.34	333-64652	4(a)33	Thirty-Third Supplemental Indenture, dated as of May 1, 2004.
4.35	(with Form 8-K dated as of December 15, 2004)	4.1	Thirty-Fourth Supplemental Indenture, dated as of November 1, 2004.
4.36	(with Form 8-K dated as of December 15, 2004)	4.2	Thirty-Fifth Supplemental Indenture, dated as of December 1, 2004.
4.37	(with Form 8-K dated as of December 15, 2004)	4.3	Thirty-Sixth Supplemental Indenture, dated as of December 1, 2004.
4.38	(with Form 8-K dated as of December 15, 2004)	4.4	Thirty-Seventh Supplemental Indenture, dated as of December 1, 2004.
4.39	(with Form 8-K dated as of May 12, 2005)	4.1	Thirty-Eighth Supplemental Indenture, dated as of May 1, 2005.
4.40	(with Form 8-K dated as of November 17, 2005)	4.1	Thirty-Ninth Supplemental Indenture, dated as of November 1, 2005.
4.41	(with Form 8-K dated as of April 6, 2006)	4.1	Fortieth Supplemental Indenture, dated as of April 1, 2006.
4.42	(with Form 8-K dated as of December 15, 2006)	4.1	Forty-First Supplemental Indenture, dated as of December 1, 2006.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
4.43	(with Form 8-K dated as of April 3, 2008)	4.1	Forty-Second Supplemental Indenture, dated as of April 1, 2008.
4.44	(with Form 8-K dated as of November 26, 2008)	4.1	Forty-Third Supplemental Indenture, dated as of November 1, 2008.
4.45	(with Form 8-K dated as of December 16, 2008)	4.1	Forty-Fourth Supplemental Indenture, dated as of December 1, 2008.
4.46	(with Form 8-K dated as of December 30, 2008)	4.3	Forty-Fifth Supplemental Indenture, dated as of December 1, 2008.
4.47	(with Form 8-K dated as of September 15, 2009)	4.1	Forty-Sixth Supplemental Indenture, dated as of September 1, 2009.
4.48	(with Form 8-K dated as of November 25, 2009)	4.1	Forty-Seventh Supplemental Indenture, dated as of November 1, 2009.
4.49	(with Form 8-K dated as of December 15, 2010)	4.5	Forty-Eighth Supplemental Indenture, dated as of December 1, 2010.
4.50	(with Form 8-K dated as of December 20, 2010)	4.1	Forty-Ninth Supplemental Indenture, dated as of December 1, 2010.
4.51	(with Form 8-K dated as of December 30, 2010)	4.1	Fiftieth Supplemental Indenture, dated as of December 1, 2010.
4.52	(with Form 8-K dated as of February 11, 2011)	4.1	Fifty-First Supplemental Indenture, dated as of February 1, 2011.
4.53	(with Form 8-K dated as of August 16, 2011)	4.1	Fifty-Second Supplemental Indenture, dated as of August 1, 2011.
4.54	(with Form 8-K dated as of December 14, 2011)	4.1	Fifty-Third Supplemental Indenture, dated as of December 1, 2011.
4.55	(with Form 8-K dated as of November 30, 2012)	4.1	Fifty-Fourth Supplemental Indenture, dated as of November 1, 2012.
4.56	(with Form 8-K dated as of August 14, 2013)	4.1	Fifty-Fifth Supplemental Indenture, dated as of August 1, 2013.
4.57	(with Form 8-K dated as of April 18, 2014)	4.1	Fifty-Sixth Supplemental Indenture, dated as of April 1, 2014.
4.58	(with Form 8-K dated as of December 18, 2014)	4.1	Fifty-Seventh Supplemental Indenture, dated as of December 1, 2014.
4.59	(with Form 8-K dated as of December 16, 2015)	4.1	Fifty-Eighth Supplemental Indenture, dated as of December 1, 2015.
4.60	(with Form 8-K dated as of December 16, 2016)	4.1	Fifty-Ninth Supplemental Indenture, dated as of December 1, 2016.

Exhibit	With Registration Number	Previously Filed [1] As Exhibit	
4.61	(with Form 8-K dated as of December 14, 2017)	4.1	Sixtieth Supplemental Indenture, dated as of December 1, 2017.
4.62	(with Form 8-K dated as of May 15, 2018)	4(a)(62)	Sixty-First Supplemental Indenture, dated as of May 1, 2018
4.63	(with Form 8-K dated as of November 26, 2019)	4.1	Sixty-Second Supplemental Indenture, dated as of November 1, 2019
4.64	(with Form 8-K dated as of June 4, 2020)	4.1	Sixty-Third Supplemental Indenture, dated as of June 1, 2020
4.65	(with Form 8-K dated as of September 30, 2020)	4.1	Sixty-Fourth Supplemental Indenture, dated as of September 1, 2020
4.66	(with Form 8-K dated as of September 30, 2021)	4.1	Sixty-Fifth Supplemental Indenture, dated as of September 1, 2021
4.67	(with Form 8-K dated as of March 8, 2022)	4.1	Sixty-Sixth Supplemental Indenture, dated as of March 1, 2022
4.68	(with Form 8-K dated as of March 29, 2023)	4.1	Sixty-Seventh Supplemental Indenture, dated as of March 1, 2023
4.69	(with Form 8-K dated as of June 8, 2023)	4.1	Sixty-Eighth Supplemental Indenture, dated as of June 1, 2023
4.70	(with Form 8-K dated as of July 23, 2025)	4.1	Sixty-Ninth Supplemental Indenture, dated as of July 1, 2025
4.71	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.72	(with Form 8-K dated as of December 15, 2004)	4.5	Supplemental Indenture No. 1, dated as of December 1, 2004 to the Indenture dated as of April 1, 1998 between Avista Corporation and JPMorgan Chase Bank, N.A.
4.73	(with Form 8-K dated as of December 15, 2010)	4.1	Loan Agreement between City of Forsyth, Montana and Avista Corporation $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A dated as of December 1, 2010.
4.74	(with 2024 Form 10-K)	4.73	Waiver of redemption right under Section 8.01 of the Loan Agreement between City of Forsyth, Montana and Avista Corporation $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A
4.75	(with Form 8-K dated as of December 15, 2010)	4.3	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A, dated as of December 1, 2010.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
4.76	(with Form 8-K dated as of December 15, 2010)	4.2	Loan Agreement between City of Forsyth, Montana and Avista Corporation $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B dated as of December 1, 2010.
4.77	(with 2024 Form 10-K)	4.76	Waiver of redemption right under Section 8.01 of the Loan Agreement between City of Forsyth, Montana and Avista Corporation $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B
4.78	(with Form 8-K dated as of December 15, 2010)	4.4	Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B, dated as of December 1, 2010.
4.79	(with March 31, 2025 Form 10-Q)	4.1	Description of the Registrant's Securities registered under Section 12 of the Securities Exchange Act of 1934.
10.1	(with Form 8-K dated as of February 11, 2011)	10.1	Credit Agreement, dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, The Bank of New York Mellon, Keybank National Association, and U.S. Bank National Association, as Co-Documentation Agents, Wells Fargo Bank National Association as Syndication Agent and an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.2	(with Form 8-K dated as of December 14, 2011)	10.1	First Amendment and Waiver Thereunder, dated as of December 14, 2011, to the Credit Agreement dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, Wells Fargo Bank National Association as an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank.
10.3	(with Form 8-K dated as of April 18, 2014)	10.1	Second Amendment to Credit Agreement, dated as of April 18, 2014, among Avista Corporation, Wells Fargo Bank, National Association, as an Issuing Bank, Union Bank, N.A. as Administrative Agent and an Issuing Bank, and the financial institutions identified hereof as Continuing Lenders and Exiting Lender.
10.4	(with Form 8-K dated as of June 8, 2023)	10.1	Fifth Amendment to Credit Agreement, dated as of June 8, 2023, among Avista Corporation, the lending financial institutions, U.S. Bank National Corporation and Wells Fargo Bank National Association as issuing banks, and MUFG Bank, LTD as Administrative Agent
10.5	(with Form 8-K dated as of June 8, 2023)	10.2	Bond Delivery Agreement, dated as of June 8, 2023, between Avista Corporation and Union Bank, N.A.
10.6	(with 2002 Form 10-K)	10(b)-3	Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
10.7	(with 2002 Form 10-K)	10(b)-4	Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.8	(with 2002 Form 10-K)	10(b)-5	Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development).
10.9	2-60728	5(g)	Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.*
10.10	2-60728	5(g)-1	Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.*
10.11	2-60728	5(h)	Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963.*
10.12	2-60728	5(h)-1	Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965.*
10.13	(with September 30, 1985 Form 10-Q)	1	Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation.*
10.14	(with 1981 Form 10-K)	10(s)-7	Ownership and Operation Agreement for Colstrip Units No. 3 & 4, dated as of May 6, 1981.*
10.15	(with 2019 Form 10-K)	10.14	Avista Corporation Executive Deferral Plan (2020 Component). [3][5]
10.16	(with 2019 Form 10-K)	10.15	Avista Corporation Supplemental Executive Retirement Plan (Post-2004 Component, Amended in 2018). [3][6]
10.17	(with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. [3]*
10.18	(with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. [3]
10.19	[2]	10.21	Avista Corporation Long-Term Incentive Plan. [3]
10.20	(with 2010 Form 10-K)	10.23	Avista Corporation Performance Award Plan Summary. [3]
10.21	(with 2023 Form 10-K)	10.24	Avista Corporation Performance Award Agreement 2023. [3]
10.22	(with 2024 Form 10-K)	10.24	Avista Corporation Performance Award Agreement 2024. [3]

EXHIBIT INDEX (CONTINUED)

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
10.23	[2]		Avista Corporation Performance Award Agreement 2025. [3]
10.24	[2]		Avista Corporation Officer Incentive Plan. [3]
10.25	(with September 30, 2019 Form 10-Q)	10.1	Form of Change of Control Plan between the Company and its Executive Officers. [3][5]
10.26	[2]		Avista Corporation Non-Employee Director Compensation.
10.27	(with Form 8-K dated January 4, 2023)	10.1	Continuing Letter of Credit Agreement dated as of December 29, 2022, among Avista Corporation and MUFG Bank Ltd., as Issuer.
19	(with 2024 Form 10-K)	19	Insider Trading Policy
21	[2]		Subsidiaries of Registrant.
23	[2]		Consent of Independent Registered Public Accounting Firm.
31.1	[2]		Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
31.2	[2]		Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002).
32	[4]		Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
97	(with 2023 Form 10-K)	97	Avista Corporation Dodd-Frank Recovery Policy
101.INS	[2]		Inline XBRL Instance Document – the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	[2]		Inline XBRL Taxonomy Extension Schema with embedded linkbases Document
104	[2]		Cover page formatted as Inline XBRL and contained in Exhibit 101.

** Exhibit originally filed with the U.S. Securities and Exchange Commission in paper format and as such, a hyperlink is not available.*

(1) Incorporated herein by reference.

(2) Filed herewith.

(3) Management contracts or compensatory plans filed as exhibits to this Form 10-K pursuant to Item 15(b).

(4) Furnished herewith.

(5) Applies to Alexis G. Alexander, Kevin J. Christie, Bryan A. Cox, Josh D. DiLuciano, Gregory C. Hesler, Latisha D. Hill, Scott J. Kinney, Ryan L. Krasselt, Wayne O. Manuel, Heather L. Rosentrater, and Jason R. Thackston.

(6) Applies to Alexis G. Alexander, Kevin J. Christie, Bryan A. Cox, Josh D. DiLuciano, Latisha D. Hill, Scott J. Kinney, Ryan L. Krasselt, Heather L. Rosentrater, and Jason R. Thackston.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

AVISTA CORPORATION

February 24, 2026	By /s/ Heather L. Rosentrater
Date	Heather L. Rosentrater President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	**Title**	**Date**
/s/ Heather L. Rosentrater Heather L. Rosentrater President and Chief Executive Officer	Principal Executive Officer and Director	February 24, 2026
/s/ Kevin J. Christie Kevin J. Christie Senior Vice President, Chief Financial Officer Treasurer, and Regulatory Affairs Officer	Principal Financial Officer	February 24, 2026
/s/ Ryan L. Krasselt Ryan L. Krasselt Vice President and Controller	Principal Accounting Officer	February 24, 2026
/s/ Scott L. Morris Scott L. Morris Chairman of the Board	Director	February 24, 2026
/s/ Julie A. Bentz Julie A. Bentz	Director	February 24, 2026
/s/ Donald C. Burke Donald C. Burke	Director	February 24, 2026
/s/ Kevin B. Jacobsen Kevin B. Jacobsen	Director	February 24, 2026
/s/ Rebecca A. Klein Rebecca A. Klein	Director	February 24, 2026
/s/ Sena M. Kwawu Sena M. Kwawu	Director	February 24, 2026
/s/ Scott H. Maw Scott H. Maw	Director	February 24, 2026
/s/ Jeffry L. Philipps Jeffry L. Philipps	Director	February 24, 2026
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 24, 2026
/s/ Janet D. Widmann Janet D. Widmann	Director	February 24, 2026

EXHIBIT 21

AVISTA CORPORATION

SUBSIDIARIES OF REGISTRANT

Subsidiary	**State or Country of Incorporation**
Avista Capital, Inc.	Washington
Avista Development, Inc.	Washington
Avista Edge, Inc.	Washington
Avista Northwest Resources, LLC	Washington
Pentzer Corporation	Washington
Pentzer Venture Holding II, Inc.	Washington
Avista Capital II	Delaware
Alaska Energy and Resources Company	Alaska
Alaska Electric Light and Power Company	Alaska
AJT Mining Properties, Inc.	Alaska
Snettisham Electric Company	Alaska
Salix, Inc.	Washington

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-33790, 333-179042 and 333-208986 on Form S-8 and in Registration Statement No. 333-287023 on Form S-3 of our reports dated February 24, 2026, relating to the financial statements of Avista Corporation, and the effectiveness of Avista Corporation's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2025.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 24, 2026

EXHIBIT 31.1

CERTIFICATION

I, Heather L. Rosentrater, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2026

/s/ Heather L. Rosentrater
Heather L. Rosentrater
President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION

I, Kevin J. Christie, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2026

/s/ Kevin J. Christie
Kevin J. Christie
Senior Vice President, Chief Financial Officer,
Treasurer and Regulatory Affairs Officer
(Principal Financial Officer)

EXHIBIT 32

AVISTA CORPORATION

CERTIFICATION OF CORPORATE OFFICERS

(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)

Each of the undersigned, Heather L. Rosentrater, President and Chief Executive Officer of Avista Corporation (the "Company"), and Kevin J. Christie, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2025 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 24, 2026

/s/ Heather L. Rosentrater
Heather L. Rosentrater
President and Chief Executive Officer

/s/ Kevin J. Christie
Kevin J. Christie
Senior Vice President, Chief Financial Officer,
Treasurer and Regulatory Affairs Officer

SELECTED FINANCIAL DATA

Avista Corporation
As of and for the years ended December 31,
Dollars in millions, except per share data and ratios

	2025	2024	2023	2022	2021	2015
FINANCIAL RESULTS						
Operating revenues	$ 1,964	$ 1,938	$ 1,752	$ 1,710	$ 1,439	$ 1,485
Operating expenses	1,610	1,632	1,494	1,520	1,211	1,223
Income from continuing operations	354	306	258	190	228	262
Interest expense	154	150	144	119	106	80
Income taxes	24	3	(34)	(17)	12	67
Net income from continuing operations	193	180	171	155	147	118
Net income (loss) from discontinued operations	—	—	—	—	—	5
Net income	$ 193	$ 180	$ 171	$ 155	$ 147	$ 123
Earnings per common share attributable to Avista Corp. shareholders—diluted:						
Earnings from continuing operations	$ 2.38	$ 2.29	$ 2.24	$ 2.12	$ 2.10	$ 1.89
Earnings from discontinued operations	—	—	—	—	—	0.08
Total	$ 2.38	$ 2.29	$ 2.24	$ 2.12	$ 2.10	$ 1.97
Earnings per common share attributable to Avista Corp. shareholders—basic:	$ 2.38	$ 2.29	$ 2.24	$ 2.13	$ 2.11	$ 1.98
COMMON STOCK STATISTICS						
Dividends paid per common share	$ 1.96	$ 1.90	$ 1.84	$ 1.76	$ 1.69	$ 1.32
Book value per common share	$ 32.96	$ 32.37	$ 31.83	$ 31.15	$ 30.14	$ 24.53
Shares of common stock (thousands):						
Outstanding at year-end	82,193	80,039	78,075	74,946	71,498	62,313
Average—basic	80,975	78,725	76,396	72,989	69,951	62,301
Average—diluted	81,051	78,820	76,495	73,093	70,085	62,708
Return on average Avista Corp. stockholders' equity:						
Total company	7.3%	7.1%	7.1%	6.9%	7.1%	8.2%
Utility only	8.4%	7.9%	7.8%	5.9%	6.7%	8.4%
Non-utility only	(3.1)%	0.4%	1.6%	15.6%	10.0%	6.5%
Common stock price:						
High	$ 43.09	$ 39.99	$ 45.29	$ 46.90	$ 49.14	$ 38.30
Low	$ 34.80	$ 31.91	$ 30.53	$ 35.72	$ 36.68	$ 29.93
Year-end close	$ 38.54	$ 36.63	$ 35.74	$ 44.34	$ 42.49	$ 35.37

SELECTED FINANCIAL DATA (continued)

Avista Corporation

As of and for the years ended December 31,

Dollars in millions, except per share data and ratios

	2025	2024	2023	2022	2021	2015
DEBT AND PREFERRED STOCK STATISTICS						
Pretax interest coverage:						
Including AFUDC/AFUCE	2.49(x)	2.27(x)	1.99(x)	2.14(x)	2.54(x)	3.46(x)
Excluding AFUDC/AFUCE	2.38(x)	2.18(x)	1.92(x)	2.05(x)	2.43(x)	3.31(x)
Embedded cost of long-term debt	5.04%	4.92%	4.98%	4.87%	4.95%	5.31%
FINANCIAL CONDITION						
Total assets	$ 8,359	$ 7,941	$ 7,702	$ 7,417	$ 6,854	$ 4,907
Total net Avista Utilities property	6,137	5,811	5,542	5,295	5,078	3,703
Avista Utilities property capital expenditures (excluding equity-related AFUDC)	553	510	485	443	436	381
Long-term debt (including current portion)	2,754	2,614	2,530	2,295	2,268	1,573
Long-term debt to affiliated trusts	52	52	52	52	52	52
Avista Corporation stockholders' equity	$ 2,709	$ 2,591	$ 2,485	$ 2,335	$ 2,155	$ 1,529

Avista Corporation

As of and for the years ended December 31,

Dollars in millions, except per share data and ratios

	2025	2024	2023	2022	2021	2015
AVISTA UTILITIES						
Electric Operations						
Electric operating revenues:						
Residential	$ 550	$ 473	$ 425	$ 415	$ 395	$ 336
Commercial	402	369	344	339	326	308
Industrial	142	131	110	108	107	112
Public street and highway lighting	9	9	8	7	7	7
Total retail	1,103	982	887	869	835	763
Wholesale	187	225	250	179	90	127
Sales of fuel	20	13	(26)	84	64	83
Other	34	81	61	14	18	25
Total electric operating revenues	$ 1,344	$ 1,301	$ 1,172	$ 1,146	$ 1,007	$ 998
Electric energy sales (millions of kWhs):						
Residential	4,114	4,018	4,020	4,154	3,955	3,571
Commercial	3,216	3,166	3,160	3,201	3,158	3,197
Industrial	1,912	1,785	1,671	1,699	1,666	1,812
Public street and highway lighting	15	17	17	17	17	23
Total retail	9,257	8,986	8,868	9,071	8,796	8,603
Wholesale	4,457	3,740	3,468	3,094	2,461	3,145
Total electric energy sales	13,714	12,726	12,336	12,165	11,257	11,748
Retail electric customers (average per year):						
Residential	376,349	371,076	366,450	361,564	356,387	327,057
Commercial	45,959	45,794	45,341	44,550	44,110	41,296
Industrial	1,159	1,175	1,188	1,193	1,205	1,353
Public street and highway lighting	761	739	690	681	666	529
Total retail electric customers	424,228	418,784	413,669	407,988	402,368	370,235
Retail electric customers (at year-end):						
Residential	379,954	374,290	370,081	363,932	359,452	330,749
Commercial	46,610	45,778	44,452	44,806	44,303	42,182
Industrial	1,174	1,164	1,158	1,195	1,195	1,362
Public street and highway lighting	870	753	638	708	672	555
Total retail electric customers	428,608	421,985	416,329	410,641	405,622	374,848
Revenue per residential kWh (cents)	13.37	11.78	10.58	9.99	9.98	9.40
Use per residential customer (kWh)	10,931	10,827	10,971	11,487	11,098	10,827
Revenue per commercial kWh (cents)	12.51	11.66	10.87	10.58	10.33	9.64
Use per commercial customer (kWh)	69,969	69,141	69,687	71,805	71,589	76,638
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	3,195	3,168	3,024	3,930	3,598	3,434
Thermal generation (from Company facilities)	4,815	4,995	5,084	4,055	3,635	3,983
Purchased power	6,040	4,965	5,121	5,065	4,954	4,899
Power exchanges	(13)	(14)	(421)	(385)	(398)	(2)
Total power resources	14,037	13,114	12,808	12,665	11,789	12,314
Energy losses and company use	(323)	(388)	(472)	(500)	(532)	(566)
Total electric energy resources	13,714	12,726	12,336	12,165	11,257	11,748

SELECTED FINANCIAL DATA (continued)

Avista Corporation

As of and for the years ended December 31,

Dollars in millions, except per share data and ratios

	2025	2024	2023	2022	2021	2015
AVISTA UTILITIES						
Electric Operations (continued)						
Retail Native Load at time of system peak						
Winter	1,832	1,869	1,771	1,860	1,696	1,529
Summer	1,837	1,831	1,809	1,810	1,889	1,638
Cooling degree days (at Spokane, Washington):						
Actual	845	903	811	758	946	805
30 year average	607	596	585	568	546	334
Actual as a percent of average	139%	152%	139%	133%	173%	241%
Natural Gas Operations						
Natural gas operating revenues:						
Residential	$ 291	$ 317	$ 326	$ 284	$ 221	$ 194
Commercial	137	163	164	140	101	97
Industrial and interruptible	12	13	17	10	8	6
Total retail	440	493	507	434	330	297
Wholesale	52	61	55	133	113	204
Transportation	13	11	8	9	9	8
Other	79	41	1	6	21	12
Total natural gas operating revenues	$ 584	$ 606	$ 571	$ 582	$ 473	$ 521
Natural gas therms delivered (millions of therms):						
Residential	209	218	226	243	220	176
Commercial	133	138	139	147	130	108
Industrial and interruptible	30	25	25	20	21	10
Total retail	372	381	390	410	371	294
Wholesale	229	272	262	280	357	809
Transportation and other	157	179	165	172	173	165
Total natural gas therms delivered	758	831	817	862	901	1,268
Retail natural gas customers (average per year):						
Residential	346,048	343,267	340,655	337,073	332,187	296,005
Commercial	37,481	37,353	37,193	36,753	36,448	34,229
Industrial and interruptible	235	237	237	232	232	296
Total retail natural gas customers	383,764	380,857	378,085	374,058	368,867	330,530
Retail natural gas customers (at year-end):						
Residential	348,037	345,278	343,384	340,048	335,166	299,509
Commercial	37,791	37,404	37,383	37,136	36,622	34,775
Industrial and interruptible	241	238	235	236	237	289
Total retail natural gas customers	386,069	382,920	381,002	377,420	372,025	334,573
Revenue per residential therm (in dollars)	$ 1.39	$ 1.46	$ 1.44	$ 1.17	$ 1.01	$ 1.10
Use per residential customer (therms)	605	635	662	719	662	593
Revenue per commercial therm (in dollars)	$ 1.03	$ 1.18	$ 1.18	$ 0.95	$ 0.77	$ 0.90
Use per commercial customer (therms)	3,547	3,694	3,730	4,001	3,578	3,128

SELECTED FINANCIAL DATA (continued)

Avista Corporation

As of and for the years ended December 31,

Dollars in millions, except per share data and ratios

	2025	2024	2023	2022	2021	2015
AVISTA UTILITIES						
Natural Gas Operations (continued)						
Heating degree days (at Spokane, Washington):						
Actual	5,782	5,875	6,012	6,811	6,124	5,614
30 year average	6,521	6,569	6,557	6,560	6,596	6,491
Actual as a percent of average	89%	89%	92%	104%	93%	86%
ALASKA ELECTRIC LIGHT AND POWER COMPANY						
Revenues	$ 47	$ 50	$ 48	$ 46	$ 45	$ 45
Total assets	$ 289	$ 283	$ 270	$ 264	$ 265	$ 266
OTHER						
Revenues	$ 1	$ 1	$ 1	$ 1	$ 1	$ 29
Total assets	$ 177	$ 194	$ 191	$ 187	$ 132	$ 39

CORPORATE INFORMATION

COMPANY HEADQUARTERS

Spokane, Washington

AVISTA ON THE INTERNET

Financial results, stock quotes, news releases, documents filed with the Securities and Exchange Commission (SEC), and information on the company's products and services are available on Avista's website at **investor.avistacorp.com**.

DIRECT STOCK PURCHASE AND DIVIDEND REINVESTMENT PLAN

Computershare sponsors and administers the Computershare Investment Plan (CIP) for Avista Corp. common stock. To invest, obtain forms, or for information about your holdings, please contact the transfer agent using the information below.

TRANSFER AGENT

Computershare
P.O. Box 43006
Providence, RI 02940-3078
800.642.7365
computershare.com/investor

INVESTOR INFORMATION

A copy of the company's financial reports, including the reports on Forms 10-K and 10-Q filed with the SEC, will be provided without charge upon request to:

Avista Corp.
Investor Relations
P.O. Box 3727 MSC-19
Spokane, WA 99220-3727
800.222.4931

ANNUAL MEETING OF SHAREHOLDERS

The company's annual meeting will be held at 8:00 a.m. PDT on Thursday, May 14, 2026.

This year's meeting will be held in a virtual format only.

EXCHANGE LISTING

Ticker Symbol: AVA
New York Stock Exchange

CERTIFICATIONS

On May 9, 2025, the Chief Executive Officer (CEO) of Avista Corp. filed a Section 303A.12(a) Annual CEO Certification with the New York Stock Exchange. The CEO Certification attests that the CEO is not aware of any violations by the company of NYSE's Corporate Governance Listing Standards.

Avista Corp. has included as exhibits to its annual report on Form 10-K for the year 2025, filed with the SEC, certifications of Avista's Chief Executive Officer and Chief Financial Officer regarding the quality of Avista's public disclosure in compliance with Section 302 of the Sarbanes-Oxley Act of 2002.

This annual report contains forward-looking statements regarding the company's current expectations. These statements are subject to a variety of risks and uncertainties that could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all factors discussed in the company's annual report on Form 10-K for the year 2025. Our 2025 annual report is provided for shareholders. It is not intended for use in connection with any sale or purchase of or any solicitation of others to buy or sell securities.

The 2025 annual report is produced through a partnership of Avista employees and companies within Avista's service area.

Design and Production: 116 & West;
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Printing: National Color Graphics.

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Managing costs is a primary goal for Avista. You can help us meet this goal by agreeing to receive future annual reports and proxy statements electronically. This service saves on the costs of printing and mailing, provides timely delivery of information, and helps protect our environment by decreasing the need for paper, printing, and mailing materials.

For more information, please visit: **investor.avistacorp.com**.

AVISTA®

IN OUR COMMITMENT TO GREEN THINKING, THIS YEAR'S ANNUAL REPORT IS PRINTED ON PAPER MADE FROM RESPONSIBLY MANAGED FORESTS.

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