UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE QUARTERLY PERIOD ENDED June 30, 2023 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 1-3701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

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

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

Registrant's telephone number, including area code: 509-489-0500

None

(Former name, former address and former fiscal year, if changed since last report)

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	New York Stock Exchange

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 and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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.

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 is a shell company (as defined in Rule 12b-2 of the Exchange Act): Yes ☐ No ☒

As of July 28, 2023, 76,525,146 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION
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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
ASU	-	Accounting Standards Update
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 the Pacific Northwest
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
CETA	-	Clean Energy Transformation Act
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 exceeds 65 degrees Fahrenheit (annual degree days above historic indicate warmer than average temperatures)
COVID-19	-	Coronavirus disease 2019, a respiratory illness declared a pandemic in March 2020
Deadband or ERM deadband	-	The first $4.0 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
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
FASB	-	Financial Accounting Standards Board
FCA	-	Fixed Cost Adjustment, the electric and natural gas decoupling mechanism in Idaho
FERC	-	Federal Energy Regulatory Commission
GAAP	-	Generally Accepted Accounting Principles
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 falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures).
IPUC	-	Idaho Public Utilities Commission
KW, KWh	-	Kilowatt (1000 watts): a measure of generating power or capability. Kilowatt-hour (1000 watt hours): a measure of energy produced over a period of time

MPSC	-	Public Service Commission of the State of Montana
MW, MWh	-	Megawatt: 1000 KW. Megawatt-hour: 1000 KWh
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
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
SOFR	-	Secured Overnight Financing Rate
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)
Watt	-	Unit of measurement of electric power or capability; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt
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 Quarterly Report on Form 10-Q), 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,” “seeks,” “anticipates,” “estimates,” “expects,” “forecasts,” “projects,” “predicts,” and similar expressions.

Forward-looking statements (including those made in this Quarterly Report on Form 10-Q) are subject to a variety of risks, uncertainties and other factors. Most of these factors are beyond our control and may have a significant effect on our operations, results of operations, financial condition or cash flows, which 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, interest rate swap derivatives, 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

- 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 security risks. In addition, any of these factors could negatively impact our liquidity and limit our access to capital, among other implications;
- 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, thereby causing serious operational and financial harm;
- severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, 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;

- explosions, fires, accidents, mechanical breakdowns or other incidents that could impair assets and may disrupt operations of any 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;
- explosions, fires, accidents or other incidents arising from or allegedly arising from our operations that could cause injuries to the public or property damage;
- 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 any 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 any 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;

Cyber and Technology 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;
- changes in costs that impede our ability to implement new information technology systems or to operate and maintain current production technology;
- changes in technologies, possibly making some of the current technology we utilize obsolete or introducing new cyber security 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;
- 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 global climate changes, including future limitations on the usage and distribution of natural gas;
- 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;

Financial 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;
- 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, our ability to effectively hedge interest rates for anticipated debt issuances, 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 affect our ability to effectively hedge energy commodity risks, including cash flow impacts and requirements for collateral;
- 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 energy demand related to customer energy efficiency, conservation measures and/or increased distributed generation;
- 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;
- 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;

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 to us from such transactions, and the market value of derivative assets and liabilities;
- default or nonperformance on the part of any 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; and
- the ability to comply with the terms of the licenses and permits for our hydroelectric or thermal generating facilities at cost-effective levels.

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. There can be no assurance our expectations, beliefs or projections will be achieved or accomplished. 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 for us to predict all such factors, nor can we assess the effect of each such factor on our business or the extent 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. Financial Information

Item 1. Condensed Consolidated Financial Statements

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Three and Six Months Ended June 30
Dollars in thousands, except per share amounts
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Operating Revenues:				
Utility revenues:				
Utility revenues, exclusive of alternative revenue programs	$ 374,285	$ 384,214	$ 867,828	$ 862,917
Alternative revenue programs	5,513	(5,793)	(13,525)	(22,570)
Total utility revenues	379,798	378,421	854,303	840,347
Non-utility revenues	139	145	265	265
Total operating revenues	379,937	378,566	854,568	840,612
Operating Expenses:				
Utility operating expenses:				
Resource costs	141,244	157,397	334,172	344,265
Other operating expenses	103,071	104,482	208,049	199,009
Depreciation and amortization	66,148	62,806	131,336	125,383
Taxes other than income taxes	24,917	26,658	58,811	60,775
Non-utility operating expenses	749	2,940	1,791	3,928
Total operating expenses	336,129	354,283	734,159	733,360
Income from operations	43,808	24,283	120,409	107,252
Interest expense	35,018	28,518	70,102	56,585
Interest expense to affiliated trusts	608	177	1,179	294
Capitalized interest	(866)	(932)	(1,708)	(2,025)
Other income-net	(2,626)	(13,934)	(9,055)	(18,785)
Income before income taxes	11,674	10,454	59,891	71,183
Income tax benefit	(5,810)	(999)	(12,438)	(11,835)
Net income	$ 17,484	$ 11,453	$ 72,329	$ 83,018
Weighted-average common shares outstanding (thousands), basic	75,983	72,624	75,576	72,205
Weighted-average common shares outstanding (thousands), diluted	76,131	72,658	75,703	72,294
Earnings per common share:				
Basic	$ 0.23	$ 0.16	$ 0.96	$ 1.15
Diluted	$ 0.23	$ 0.16	$ 0.96	$ 1.15

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Three and Six Months Ended June 30
Dollars in thousands
(Unaudited)

	Three months ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Net income	$ 17,484	$ 11,453	$ 72,329	$ 83,018
Other Comprehensive Income (Loss):				
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of ($5), $73, ($10) and $146, respectively	(19)	273	(37)	549
Total other comprehensive income (loss)	(19)	273	(37)	549
Comprehensive income	$ 17,465	$ 11,726	$ 72,292	$ 83,567

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

	June 30, 2023	December 31, 2022
Assets:		
Current Assets:		
Cash and cash equivalents	$ 15,704	$ 13,428
Accounts and notes receivable-less allowances of $4,871 and $6,473, respectively	141,643	255,746
Inventory	115,805	107,674
Regulatory assets	163,906	193,787
Other current assets	89,881	151,167
Total current assets	526,939	721,802
Net utility property	5,548,651	5,444,709
Goodwill	52,426	52,426
Non-current regulatory assets	861,491	833,328
Other property and investments-net and other non-current assets	381,808	365,085
Total assets	$ 7,371,315	$ 7,417,350
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 103,587	$ 202,954
Current portion of long-term debt	7,000	13,500
Short-term borrowings	203,000	463,000
Regulatory liabilities	79,093	95,665
Other current liabilities	148,483	189,415
Total current liabilities	541,163	964,534
Long-term debt	2,530,001	2,281,013
Long-term debt to affiliated trusts	51,547	51,547
Pensions and other postretirement benefits	92,741	93,901
Deferred income taxes	703,683	674,995
Non-current regulatory liabilities	845,022	840,837
Other non-current liabilities and deferred credits	206,737	175,855
Total liabilities	4,970,894	5,082,682
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Equity:		
Shareholders’ Equity:		
Common stock, no par value; 200,000,000 shares authorized; 76,524,184 and 74,945,948 shares issued and outstanding, respectively	1,588,503	1,525,185
Accumulated other comprehensive loss	(2,095)	(2,058)
Retained earnings	814,013	811,541
Total shareholders’ equity	2,400,421	2,334,668
Total liabilities and equity	$ 7,371,315	$ 7,417,350

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Six Months Ended June 30
Dollars in thousands
(Unaudited)

	2023	2022
Operating Activities:		
Net income	$ 72,329	$ 83,018
Non-cash items included in net income:		
Depreciation and amortization	131,367	125,445
Deferred income tax provision and investment tax credits	(20,565)	(12,930)
Power and natural gas cost deferrals, net	(31,559)	(19,326)
Amortization of debt expense	1,980	1,042
Stock-based compensation expense	5,460	3,646
Equity-related AFUDC	(3,172)	(3,614)
Pension and other postretirement benefit expense	6,693	10,557
Other regulatory assets and liabilities	(31,997)	9,291
Other deferred debits and credits	32,351	(3,732)
Change in decoupling regulatory deferral	14,383	22,550
Realized and unrealized loss (gain) on assets and investments	2,752	(13,144)
Other	(2,436)	4,749
Contributions to defined benefit pension plan	(6,666)	(28,000)
Cash paid for settlement of interest rate swap agreements	(409)	(17,035)
Cash received for settlement of interest rate swap agreements	7,869	—
Changes in certain current assets and liabilities:		
Accounts and notes receivable	111,428	33,206
Inventory	(8,131)	(21,058)
Collateral posted for derivative instruments	116,602	18,131
Income taxes receivable	7,476	(168)
Other current assets	(20,228)	(1,294)
Accounts payable	(96,080)	(13,530)
Other current liabilities	(19,886)	28,137
Net cash provided by operating activities	269,561	205,941
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(226,746)	(210,646)
Issuance of notes receivable	(1,500)	(1,772)
Equity and property investments	(6,481)	(7,765)
Other	652	764
Net cash used in investing activities	(234,075)	(219,419)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Six Months Ended June 30
Dollars in thousands
(Unaudited)

	2023	2022
Financing Activities:		
Net decrease in short-term borrowings	$ (260,000)	$ (126,000)
Proceeds from issuance of long-term debt	250,000	399,856
Maturity of long-term debt and finance leases	(8,118)	(251,543)
Issuance of common stock, net of issuance costs	59,525	60,765
Cash dividends paid	(69,942)	(64,077)
Other	(4,675)	(6,072)
Net cash provided by (used in) financing activities	(33,210)	12,929
Net increase (decrease) in cash and cash equivalents	2,276	(549)
Cash and cash equivalents at beginning of period	13,428	22,168
Cash and cash equivalents at end of period	$ 15,704	$ 21,619

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

Avista Corporation

For the Three and Six Months Ended June 30
Dollars in thousands
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
Common Stock, Shares:				
Shares outstanding at beginning of period	75,762,598	72,438,447	74,945,948	71,497,523
Shares issued	761,586	537,635	1,578,236	1,478,559
Shares outstanding at end of period	76,524,184	72,976,082	76,524,184	72,976,082
Common Stock, Amount:				
Balance at beginning of period	$ 1,555,651	$ 1,418,421	$ 1,525,185	$ 1,380,152
Equity compensation expense	3,239	1,802	5,460	3,647
Issuance of common stock, net of issuance costs	29,613	22,879	59,525	60,765
Payment of minimum tax withholdings for share-based payment awards	—	—	(1,667)	(1,462)
Balance at end of period	1,588,503	1,443,102	1,588,503	1,443,102
Accumulated Other Comprehensive Loss:				
Balance at beginning of period	(2,076)	(10,763)	(2,058)	(11,039)
Other comprehensive income (loss)	(19)	273	(37)	549
Balance at end of period	(2,095)	(10,490)	(2,095)	(10,490)
Retained Earnings:				
Balance at beginning of period	831,736	825,642	811,541	785,631
Net income	17,484	11,453	72,329	83,018
Dividends on common stock	(35,207)	(32,213)	(69,857)	(63,767)
Balance at end of period	814,013	804,882	814,013	804,882
Total equity	$ 2,400,421	$ 2,237,494	$ 2,400,421	$ 2,237,494
Dividends declared per common share	$ 0.46	$ 0.44	$ 0.92	$ 0.88

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

The accompanying condensed consolidated financial statements of Avista Corp. as of and for the interim periods ended June 30, 2023 and June 30, 2022 are unaudited; however, in the opinion of management, the statements reflect all adjustments necessary for a fair statement of the results for the interim periods. All such adjustments are of a normal recurring nature. The condensed consolidated financial statements have been prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. The Condensed Consolidated Statements of Income for the interim periods are not necessarily indicative of the results to be expected for the full year. These condensed consolidated financial statements do not contain the detail or footnote disclosure concerning accounting policies and other matters which would be included in full fiscal year consolidated financial statements; therefore, they should be read in conjunction with the Company's audited consolidated financial statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2022 (2022 Form 10-K).

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, with the exception of AJT Mining Properties, Inc., which is a subsidiary of AERC. See Note 17 for business segment information.

Basis of Reporting

The condensed 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 were eliminated in consolidation. The accompanying condensed consolidated financial statements include the Company’s proportionate share of utility plant and related operations resulting from its interests in jointly owned plants.

Regulation

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

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Condensed 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 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 income statement impact. 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 netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any 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 Condensed 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 Condensed Consolidated Balance Sheets. See Note 12 for the Company’s fair value disclosures.

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 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. See Note 16 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU 2022-03 "Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions"

In June 2022, the FASB issued ASU 2022-03, Fair Value Measurement (Topic 820): Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions. The purpose of this guidance is to clarify that a contractual restriction on the ability to sell an equity security is not considered part of the unit of account of the equity security, and therefore should not be considered when measuring the equity security's fair value. Additionally, an entity cannot separately recognize and measure a contractual sale restriction. This guidance also adds specific disclosures related to equity securities subject to contractual sale restrictions, including (i) the fair value of equity securities subject to contractual sale restrictions reflected in the balance sheet and (ii) the nature and remaining duration of the restrictions, and (iii) the circumstances that could cause a lapse in the restrictions. The amendments are effective on January 1, 2024, with early adoption permitted. The amendments must be applied using a prospective approach with any adjustments from the adoption of the amendments recognized in earnings and disclosed upon adoption. The Company does not expect the impact of these amendments to be material.

NOTE 3. BALANCE SHEET COMPONENTS

Inventory

Inventories of materials and supplies, emission allowances, fuel stock and stored natural gas are recorded at average cost and consisted of the following as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023	December 31, 2022
Materials and supplies	$ 80,569	$ 75,766
Emission allowances	14,558	—
Stored natural gas	14,952	26,788
Fuel stock	5,726	5,120
Total	$ 115,805	$ 107,674

Other Current Assets

Other current assets consisted of the following as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023	December 31, 2022
Prepayments	$ 48,039	$ 30,201
Income taxes receivable	23,264	30,740
Derivative assets net of collateral	121	18,198
Collateral posted for derivative instruments after netting with outstanding derivatives	9,770	66,142
Other	8,687	5,886
Total	$ 89,881	$ 151,167

Net Utility Property

Net utility property, which is recorded at original cost, net of accumulated depreciation, consisted of the following as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023	December 31, 2022
Utility plant in service	$ 7,619,473	$ 7,561,688
Construction work in progress	175,010	164,147
Total	7,794,483	7,725,835
Less: Accumulated depreciation and amortization	2,245,832	2,281,126
Total	$ 5,548,651	$ 5,444,709

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 June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023	December 31, 2022
Equity investments	$ 149,675	$ 147,809
Operating lease ROU assets	68,594	68,238
Finance lease ROU assets	38,235	40,056
Non-utility property	30,995	25,401
Notes receivable	18,466	17,954
Long-term prepaid license fees	17,771	17,936
Pension assets	19,137	13,382
Investment in affiliated trust	11,547	11,547
Deferred compensation assets	7,428	7,541
Held for sale	3,259	—
Other	16,701	15,221
Total	$ 381,808	$ 365,085

Other Current Liabilities

Other current liabilities consisted of the following as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023	December 31, 2022
Accrued taxes other than income taxes	$ 30,838	$ 38,568
Derivative liabilities	8,585	26,910
Employee paid time off accruals	33,022	29,279
Accrued interest	27,107	20,863
Deferred wholesale revenue	—	8,481
Pensions and other postretirement benefits	13,255	15,625
Other	35,676	49,689
Total	$ 148,483	$ 189,415

Other Non-Current Liabilities and Deferred Credits

Other non-current liabilities and deferred credits consisted of the following as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023	December 31, 2022
Operating lease liabilities	$ 66,537	$ 64,284
Finance lease liabilities	40,795	42,495
Deferred investment tax credits	28,509	28,784
Climate Commitment Act obligations	32,994	—
Asset retirement obligations	15,946	15,783
Derivative liabilities	6,044	7,892
Other	15,912	16,617
Total	$ 206,737	$ 175,855

Regulatory Assets and Liabilities

Regulatory assets and liabilities consisted of the following as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023		December 31, 2022	
	Current	Non-Current	Current	Non-Current
Regulatory Assets				
Energy commodity derivatives	$ 41,198	$ 18,370	$ 112,090	$ 18,185
Decoupling surcharge	4,105	3,129	6,250	5,449
Deferred natural gas costs	88,897	—	52,091	—
Deferred power costs	29,706	20,527	23,356	24,043
Deferred income taxes	—	240,143	—	240,325
Pension and other postretirement benefit plans	—	132,530	—	135,337
Interest rate swaps	—	182,793	—	185,919
AFUDC above FERC allowed rate	—	50,365	—	51,649
Settlement with Coeur d'Alene Tribe	—	37,251	—	37,809
Advanced meter infrastructure	—	30,863	—	32,381
Utility plant abandoned	—	30,563	—	24,389
Deferred Climate Commitment Act costs	—	32,008	—	—
COVID-19 deferrals	—	9,230	—	9,793
Unamortized debt repurchase costs	—	5,934	—	6,177
Demand side management programs	—	485	—	3,683
Other regulatory assets	—	67,300	—	58,189
Total regulatory assets	$ 163,906	$ 861,491	$ 193,787	$ 833,328
Regulatory Liabilities				
Income tax related liabilities	$ 48,879	$ 365,954	$ 73,267	$ 390,734
Deferred natural gas costs	4,924	—	—	—
Decoupling rebate	13,066	26,798	9,469	20,476
Utility plant retirement costs	—	403,291	—	376,817
Interest rate swaps	—	23,402	—	24,204
COVID-19 deferrals	—	11,069	—	11,874
Other regulatory liabilities	12,224	14,508	12,929	16,732
Total regulatory liabilities	$ 79,093	$ 845,022	$ 95,665	$ 840,837

NOTE 4. REVENUE

The core principle of the revenue recognition accounting 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. Given that all revenue recognition criteria are met upon the delivery of energy to customers, revenue is recognized immediately at that time.

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

Non-Derivative Wholesale Contracts

The Company has certain wholesale contracts which are not accounted for as derivatives and, accordingly, 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)

ASC 606 retained existing GAAP associated with alternative revenue programs, which specified alternative revenue programs are contracts between an entity and a regulator of utilities, not a contract between an entity and a customer. GAAP requires an entity to present revenue arising from alternative revenue programs separately from revenues arising from contracts with customers on the face of the Condensed 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 Condensed 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 that will be surcharged or rebated to customers in future periods. GAAP requires that for any 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 current period Condensed Consolidated Statement of Income. Any amounts included in the Company's decoupling program 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 Condensed 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 specifically excluded from revenue from contracts with customers and therefore disclosed separately. The revenue or loss is recognized for these items upon the settlement/expiration of the derivative contract. Derivative revenue includes those transactions entered into and settled within the same month.

Other Utility Revenue

Other utility revenue includes rent, sales of materials, late fees and other charges that do not represent contracts with customers. Other utility revenue also includes the provision for earnings sharing. This revenue is excluded from revenue from contracts with customers, as this revenue does not represent items where a customer is a party that has contracted with the Company to 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 its 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 three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2023	2022	2023	2022
Utility-related taxes	$ 16,133	$ 14,908	$ 41,872	$ 37,042

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 June 30, 2023, the Company estimates it had unsatisfied capacity performance obligations of $10.2 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 three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2023	2022	2023	2022
Avista Utilities				
Revenue from contracts with customers	$ 294,129	$ 287,922	$ 772,904	$ 693,259
Derivative revenues	66,580	84,403	63,518	141,776
Alternative revenue programs	5,513	(5,793)	(13,525)	(22,570)
Deferrals and amortizations for rate refunds to customers	228	(500)	645	(131)
Other utility revenues	2,154	2,483	5,204	5,053
Total Avista Utilities	368,604	368,515	828,746	817,387
AEL&P				
Revenue from contracts with customers	11,023	10,266	25,234	23,221
Deferrals and amortizations for rate refunds to customers	—	(517)	—	(565)
Other utility revenues	171	157	323	304
Total AEL&P	11,194	9,906	25,557	22,960
Other non-utility revenues	139	145	265	265
Total operating revenues	$ 379,937	$ 378,566	$ 854,568	$ 840,612

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 three and six months ended June 30 (dollars in thousands):

	2023			2022		
	Avista Utilities	AEL&P	Total Utility	Avista Utilities	AEL&P	Total Utility
Three months ended June 30:						
ELECTRIC OPERATIONS						
Revenue from contracts with customers						
Residential	$ 86,499	$ 4,418	$ 90,917	$ 84,108	$ 4,156	$ 88,264
Commercial	81,346	6,544	87,890	80,713	6,051	86,764
Industrial	27,956	—	27,956	27,253	—	27,253
Public street and highway lighting	1,980	61	2,041	1,912	59	1,971
Total retail revenue	197,781	11,023	208,804	193,986	10,266	204,252
Transmission	8,475	—	8,475	8,417	—	8,417
Other revenue from contracts with customers	6,934	—	6,934	7,409	—	7,409
Total electric revenue from contracts with customers	$ 213,190	$ 11,023	$ 224,213	$ 209,812	$ 10,266	$ 220,078
Six months ended June 30:						
ELECTRIC OPERATIONS						
Revenue from contracts with customers						
Residential	$ 209,322	$ 11,299	$ 220,621	$ 205,111	$ 10,617	$ 215,728
Commercial	162,572	13,810	176,382	164,283	12,485	176,768
Industrial	53,123	—	53,123	52,145	—	52,145
Public street and highway lighting	3,935	125	4,060	3,776	119	3,895
Total retail revenue	428,952	25,234	454,186	425,315	23,221	448,536
Transmission	16,422	—	16,422	13,102	—	13,102
Other revenue from contracts with customers	24,227	—	24,227	16,171	—	16,171
Total electric revenue from contracts with customers	$ 469,601	$ 25,234	$ 494,835	$ 454,588	$ 23,221	$ 477,809

The following table disaggregates revenue from contracts with customers associated with the Company's natural gas operations for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2023	2022	2023	2022
	Avista Utilities	Avista Utilities	Avista Utilities	Avista Utilities
NATURAL GAS OPERATIONS				
Revenue from contracts with customers				
Residential	$ 48,004	$ 48,480	$ 188,840	$ 151,695
Commercial	25,477	23,736	97,802	74,357
Industrial and interruptible	4,128	2,346	9,656	5,308
Total retail revenue	77,609	74,562	296,298	231,360
Transportation	1,923	2,142	4,192	4,499
Other revenue from contracts with customers	1,407	1,406	2,813	2,812
Total natural gas revenue from contracts with customers	$ 80,939	$ 78,110	$ 303,303	$ 238,671

NOTE 5. LEASES

In March 2023, the Company entered into an agreement with Rathdrum Power, LLC (Rathdrum) amending and restating the previously existing PPA for purchase of all the output of the Lancaster plant, a 270 MW natural gas-fired combined cycle combustion turbine. The restated agreement meets the definition of a lease, and all payments are variable in nature, based on capacity, usage or performance of the plant. Therefore, there is no resulting lease obligation or corresponding ROU asset recorded by the Company.

The Company previously had a variable interest in Rathdrum through the PPA, however did not consider itself the primary beneficiary of the entity. As a result of entering the amended and restated PPA, the Company reconsidered whether Rathdrum is a variable interest entity, concluding Rathdrum no longer meets the definition of a variable interest entity. This conclusion does not materially impact the Company's financial statements.

NOTE 6. 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 derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives 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 June 30, 2023 expected to be delivered or mature in the respective years shown (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
Remainder 2023	5	42	18,192	56,775	129	661	577	10,740
2024	—	—	10,560	54,983	31	400	1,370	10,358
2025	—	—	3,710	12,305	—	96	1,115	1,125
2026	—	—	450	1,350	—	—	—	—

As of June 30, 2023, there were no expected deliveries of energy commodity derivatives after 2026.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2022 expected to be delivered or mature in the respective years shown (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
2023	5	—	19,140	79,253	136	1,011	4,145	29,473
2024	—	—	533	30,658	—	—	1,370	9,668
2025	—	—	450	4,895	—	—	1,115	1,125

As of December 31, 2022, there were no expected deliveries of energy commodity derivatives after 2025.

(1) Physical transactions represent commodity transactions in which Avista Corp. will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swap derivatives, options, or forward 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 collected 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 June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023	December 31, 2022
Number of contracts	17	19
Notional amount (in United States dollars)	$ 8,479	$ 8,563
Notional amount (in Canadian dollars)	11,255	11,659

Interest Rate Swap Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives. These interest rate swap derivatives are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the unsettled interest rate swap derivatives outstanding as of June 30, 2023 and December 31, 2022 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
June 30, 2023	2	$ 20,000	2024
December 31, 2022	4	$ 40,000	2023
	1	10,000	2024

See Note 10 for discussion of the issuance of first mortgage bonds and the related settlement of interest rate swaps in connection with the pricing of the bonds in March 2023.

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. Avista Corp. is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, Avista Corp. receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Condensed Consolidated Balance Sheet as of June 30, 2023 and December 31, 2022 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 derivative instruments recorded on the Condensed Consolidated Balance Sheet as of June 30, 2023 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current assets	$ 16	$ —	$ —	$ 16
Interest rate swap derivatives				
Other property and investments-net and other non-current assets	2,883	—	—	2,883
Energy commodity derivatives				
Other current assets	715	(610)	—	105
Other property and investments-net and other non-current assets	447	(282)	—	165
Other current liabilities	27,571	(68,874)	32,718	(8,585)
Other non-current liabilities and deferred credits	4,552	(23,087)	12,491	(6,044)
Total derivative instruments recorded on the balance sheet	$ 36,184	$ (92,853)	$ 45,209	$ (11,460)

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2022 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netted	Net Asset (Liability) on Balance Sheet
Foreign currency exchange derivatives				
Other current assets	$ 43	$ —	$ —	$ 43
Other current liabilities	—	(3)	—	(3)
Interest rate swap derivatives				
Other current assets	8,536	—	—	8,536
Other property and investments-net and other non-current assets	2,648	—	—	2,648
Other current liabilities	—	(52)	—	(52)
Energy commodity derivatives				
Other current assets	32,257	(22,638)	—	9,619
Other property and investments-net and other non-current assets	312	(16)	—	296
Other current liabilities	107,902	(229,607)	94,850	(26,855)
Other non-current liabilities and deferred credits	6,049	(24,530)	10,589	(7,892)
Total derivative instruments recorded on the balance sheet	$ 157,747	$ (276,846)	$ 105,439	$ (13,660)

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 a downgrade in Avista Corp.'s credit ratings or changes in market prices, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. 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 Avista Corp.'s collateral outstanding related to its derivative instruments as of June 30, 2023 and December 31, 2022 (in thousands):

	June 30, 2023	December 31, 2022
Energy commodity derivatives		
Cash collateral posted	$ 54,978	$ 171,581
Letters of credit outstanding	16,000	49,425
Balance sheet offsetting	45,209	105,439

No letters of credit or cash collateral were outstanding related to interest rate swap derivatives as of June 30, 2023 and December 31, 2022.

Certain of Avista Corp.’s derivative instruments contain provisions that require 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 all 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 June 30, 2023 and December 31, 2022 (in thousands):

	June 30, 2023	December 31, 2022
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	$ —	$ 52
Additional collateral to post	—	52

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

Avista Utilities

The Company contributed $6.7 million in cash to the pension plan for the six months ended June 30, 2023, and expects to contribute $10.0 million in 2023.

The Company uses a December 31 measurement date for its defined benefit pension and other postretirement benefit plans. The following table sets forth the components of net periodic benefit costs for the three and six months ended June 30 (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2023	2022	2023	2022
Three months ended June 30:				
Service cost	$ 3,100	$ 6,229	$ 532	$ 1,097
Interest cost	8,521	6,520	1,909	1,384
Expected return on plan assets	(10,922)	(10,950)	(891)	(700)
Amortization of prior service cost	123	75	(263)	(275)
Net loss recognition	1,185	939	(8)	870
Net periodic benefit cost	$ 2,007	$ 2,813	$ 1,279	$ 2,376
Six months ended June 30:				
Service cost	$ 7,994	$ 12,000	$ 1,350	$ 2,160
Interest cost	15,753	13,427	2,953	2,824
Expected return on plan assets	(21,844)	(21,901)	(1,782)	(1,400)
Amortization of prior service cost	246	150	(526)	(550)
Net loss recognition	2,024	2,087	525	1,760
Net periodic benefit cost	$ 4,173	$ 5,763	$ 2,520	$ 4,794

Total service costs in the table above are recognized in the same accounts as the associated 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 40 percent of all labor and benefits is capitalized to utility property and 60 percent is expensed to utility other operating expenses.

The non-service portion of costs in the table above are recorded to other expense below income from operations in the Condensed Consolidated Statements of Income or capitalized as a regulatory asset. Approximately 40 percent of the costs are capitalized to regulatory assets and 60 percent is expensed to the income statement.

NOTE 8. INCOME TAXES

In accordance with interim reporting requirements, the Company uses an estimated annual effective tax rate for computing its provisions for income taxes. An estimate of annual income tax expense (or benefit) is made each interim period using estimates for annual pre-tax income, income tax adjustments, and tax credits. The estimated annual effective tax rates do not include discrete events such as tax law changes, examination settlements, accounting method changes, or adjustments to tax expense or benefits attributable to prior years. Discrete events are recorded in the interim period in which they occur or become known. The estimated annual tax rate is applied to year-to-date pre-tax income to determine income tax expense (or benefit) for the interim period consistent with the annual estimate. In subsequent interim periods, income tax expense (or benefit) for the period is computed as the difference between the year-to-date amount reported for the previous interim period and the current period’s year-to-date amount.

The following table summarizes the significant factors impacting the difference between the Company's effective tax rate and the federal statutory rate for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,				Six months ended June 30,			
	2023		2022		2023		2022	
Federal income taxes at statutory rates	$ 2,452	21.0 %	$ 2,195	21.0 %	$ 12,577	21.0 %	$ 14,948	21.0 %
Increase (decrease) in tax resulting from:								
Flow through related to deduction of meters and mixed service costs (1)	(5,689)	(48.7)	(2,401)	(23.0)	(19,212)	(32.1)	(19,835)	(27.9)
Tax effect of regulatory treatment of utility plant differences	(1,525)	(13.1)	(976)	(9.3)	(5,212)	(8.7)	(7,298)	(10.3)
State income tax expense	232	2.0	78	0.7	798	1.3	901	1.3
Tax credits	(1,135)	(9.7)	—	—	(1,135)	(1.9)	—	—
Other	(145)	(1.3)	105	1.0	(254)	(0.4)	(551)	(0.7)
Total income tax benefit	$ (5,810)	(49.8)%	$ (999)	(9.6)%	$ (12,438)	(20.8)%	$ (11,835)	(16.6)%

(1) 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 as a result of flowing through the benefits related to meters and mixed service costs. The decrease in income tax expense offsets the increases in base rates granted to the Company in these general rate cases.

NOTE 9. 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 2028 and the option to extend for two additional one year periods (subject to customary conditions). In June 2023, the then-existing agreement was amended to increase the capacity of the committed line of credit from $400 million to $500 million, extend the expiration date and replace the London Interbank Offered Rate (LIBOR) provisions with SOFR provisions. The committed line of credit is secured by non-transferable first mortgage bonds of Avista Corp. issued to the agent bank that would only be payable in the event, and then only to the extent, Avista Corp. defaults on its obligations under the committed line of credit. The bonds would bear interest at a rate of 12 percent.

Balances outstanding and interest rates on borrowings (excluding letters of credit) under Avista Corp.’s revolving committed line of credit were as follows as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023	December 31, 2022
Borrowings outstanding at end of period	$ 203,000	$ 313,000
Letters of credit outstanding at end of period	4,638	35,563
Average interest rate on borrowings at end of period	6.24 %	5.31 %

In December 2022, Avista Corp. entered into a revolving credit agreement in the amount of $100 million. As of December 31, 2022, Avista Corp. did not have any outstanding borrowings under this agreement. The agreement was terminated in June 2023.

The borrowings outstanding under Avista Corp.'s committed lines of credit were classified as short-term borrowings on the Condensed Consolidated Balance Sheets.

2022 Term Loan

In December 2022, Avista Corp. entered into a term loan agreement in the amount of $150 million with a maturity date of March 30, 2023. Avista Corp. borrowed the entire $150 million available under the agreement in 2022, and repaid the entire outstanding balance in March 2023.

2022 Letter of Credit Facility

In December 2022, Avista Corp. entered into a letter of credit agreement in the aggregate amount of $50 million. Either party may terminate the agreement at any time.

Avista Corp. had $16.0 million and $18.5 million in letters of credit outstanding under this agreement as of June 30, 2023 and December 31, 2022, respectively. Letters of credit are not reflected on the Condensed 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 the 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 the case of the letter of credit agreement, other obligations. The committed line of credit agreement 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 June 30, 2023, the Company was in compliance with this covenant.

AEL&P

AEL&P has a committed line of credit in the amount of $25.0 million that expires in June 2028. There were no borrowings or letters of credit outstanding under this agreement as of June 30, 2023 and December 31, 2022. 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.

NOTE 10. LONG-TERM DEBT

In March 2023, the Company issued and sold $250.0 million of 5.66 percent first mortgage bonds due in 2053 with institutional investors in the private placement market. In connection with the pricing of the first mortgage bonds in March 2023, the Company cash-settled four interest rate swap derivatives (notional aggregate amount of $40.0 million) and received a net amount of $7.5 million, which will be amortized as a component of interest expense over the life of the debt. See Note 6 for a discussion of interest rate swap derivatives.

A portion of the net proceeds from the sale of these bonds will be used for the construction or improvement of utility facilities, and a portion was used to refinance existing indebtedness, including the repayment of Avista Corp.'s $150 million term loan.

NOTE 11. 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 $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. Effective July 3, 2023, the reference to LIBOR in the formulation for the distribution rate on these securities was replaced with three-month CME Term SOFR, as calculated and published by CME Group Benchmark Administration, Ltd. (a successor administrator), plus a tenor spread adjustment of 0.26 percent. Accordingly, the distribution rate on the Preferred Trust Securities will now be the three-month CME Term SOFR plus 1.137 percent calculated and reset quarterly.

The distribution rates were as follows during the six months ended June 30, 2023 and the year ended December 31, 2022:

	June 30, 2023	December 31, 2022
Low distribution rate	5.64 %	1.05 %
High distribution rate	6.37 %	5.64 %
Distribution rate at the end of the period	6.37 %	5.64 %

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. The 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 $10.0 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 condensed consolidated financial statements as Avista Corp. is not the primary beneficiary. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Condensed Consolidated Balance Sheets. Interest expense to affiliated trusts in the Condensed Consolidated Statements of Income represents interest expense on these debentures.

NOTE 12. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable, and short-term borrowings as shown on the Condensed Consolidated Balance Sheets are reasonable estimates of their fair values. The carrying values of long-term debt (including current portion and material finance leases) and long-term debt to affiliated trusts as shown on the Condensed 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 measurement) and the lowest priority to fair values derived from unobservable inputs (Level 3 measurement).

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 those 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 including the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), and 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 Condensed Consolidated Balance Sheets as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023		December 31, 2022	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 1,107,000	$ 975,122	$ 1,113,500	$ 966,881
Long-term debt (Level 3)	1,450,000	1,137,437	1,200,000	881,480
Snettisham finance lease obligation (Level 3)	44,113	40,500	45,730	41,700
Long-term debt to affiliated trusts (Level 3)	51,547	42,284	51,547	42,836

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 60.96 percent to 106.85 percent of the principal amount, where 100.0 percent of the principal amount (adjusted for unamortized discount or premium) represents the carrying value recorded on the Condensed 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 was discounted to present value using the Morgan Markets A Ex-Fin discount rate as published on June 30, 2023 and December 31, 2022.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Condensed Consolidated Balance Sheets as of June 30, 2023 and December 31, 2022 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
June 30, 2023					
Assets:					
Energy commodity derivatives	$ —	$ 33,285	$ —	$ (33,015)	$ 270
Foreign currency exchange derivatives	—	16	—	—	16
Interest rate swap derivatives	—	2,883	—	—	2,883
Equity Investments	—	—	48,453	—	48,453
Deferred compensation assets					
Mutual Funds:					
Fixed income securities (3)	1,142	—	—	—	1,142
Equity securities (3)	6,140	—	—	—	6,140
Total	$ 7,282	$ 36,184	$ 48,453	$ (33,015)	$ 58,904
Liabilities:					
Energy commodity derivatives (2)	$ —	$ 81,132	$ 11,721	$ (78,224)	$ 14,629
Total	$ —	$ 81,132	$ 11,721	$ (78,224)	$ 14,629
December 31, 2022					
Assets:					
Energy commodity derivatives (2)	$ —	$ 146,232	$ 288	$ (136,605)	$ 9,915
Foreign currency exchange derivatives	—	43	—	—	43
Interest rate swap derivatives	—	11,184	—	—	11,184
Equity Investments	—	—	54,284	—	54,284
Deferred compensation assets					
Mutual Funds:					
Fixed income securities (3)	1,267	—	—	—	1,267
Equity securities (3)	6,132	—	—	—	6,132
Total	$ 7,399	$ 157,459	$ 54,572	$ (136,605)	$ 82,825
Liabilities:					
Energy commodity derivatives (2)	$ —	$ 258,769	$ 18,022	$ (242,044)	$ 34,747
Foreign currency exchange derivatives	—	3	—	—	3
Interest rate swap derivatives	—	52	—	—	52
Total	$ —	$ 258,824	$ 18,022	$ (242,044)	$ 34,802

(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 any payables and receivables for cash collateral held or placed with these same counterparties.

(2) The Level 3 energy commodity derivative balances are associated with natural gas exchange agreements.

(3) Included in other property and investments-net and other non-current assets on the Condensed 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 Condensed Consolidated Balance Sheets is due to netting arrangements with certain counterparties. See Note 6 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. In particular, 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.

To establish fair values for interest rate swap derivatives, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness, with consideration given to the potential non-performance risk by the Company. Future cash flows of the interest rate swap derivatives are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

To establish fair value for foreign currency derivatives, the Company uses forward market curves for Canadian dollars against the US dollar and multiplies the difference between the locked-in price and the market price by the notional amount of the derivative. Forward foreign currency market curves are provided by third party brokers. The Company's credit spread is factored into the locked-in price of the foreign exchange contracts.

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 June 30, 2023 (dollars in thousands):

	Fair Value (Net) at June 30, 2023	Valuation Technique	Unobservable Input	Range and Weighted Average Price
Natural gas exchange agreement	$ (11,721)	Internally derived weighted average cost of gas	Forward purchase prices	$2.53 - $3.39/mmBTU $2.99 Weighted Average
			Forward sales prices	$2.92 - $9.53/mmBTU $6.79 Weighted Average
			Purchase volumes	140,000 - 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's management 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, time to liquidity event and the market discount for lack of liquidity. In the event there are relevant market transactions for the same or similar securities of the subject company or there is the reasonable possibility of a transaction occurring, those transactions are 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 the 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 June 30, 2023 (dollars in thousands):

	Fair Value at June 30, 2023	Valuation Technique	Unobservable Input	Range
Equity investments	$ 48,453	Market approach	Comparable enterprise values	$130,000-$388,600 $246,000 Average
			Time to liquidity event	0 to 2 years
			Probability weighting	75%/25%
		Discounted cash flows	Revenue market multiples	1.39x to 7.10x Revenue 3.39x Average
			Market exit reduction	50%
			Discount rate	25%
			Annual revenues	$14,000 - $265,000
			Terminal date	2026

The following table presents activity for assets and liabilities measured at fair value using significant unobservable inputs (Level 3) for the three and six months ended June 30 (dollars in thousands):

	Natural Gas Exchange Agreement (1)	Equity Investments	Total
Three Months Ended June 30, 2023:			
Beginning balance	$ (11,062)	$ 51,014	$ 39,952
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities	(1,016)	—	(1,016)
Recognized in net income	—	(2,561)	(2,561)
Purchases and debt conversions	—	—	—
Settlements	357	—	357
Other	—	—	—
Ending balance as of June 30, 2023	$ (11,721)	$ 48,453	$ 36,732
Three Months Ended June 30, 2022:			
Beginning balance	$ (6,197)	$ —	$ (6,197)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities	5,196	—	5,196
Settlements	(1,288)	—	(1,288)
Ending balance as of June 30, 2022	$ (2,289)	$ —	$ (2,289)
Six Months Ended June 30, 2023:			
Beginning balance	$ (17,734)	$ 54,284	$ 36,550
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities	5,767	—	5,767
Recognized in net income	—	(5,198)	(5,198)
Purchases and debt conversions	—	2,367	2,367
Settlements	246	—	246
Other	—	(3,000)	(3,000)
Ending balance as of June 30, 2023	$ (11,721)	$ 48,453	$ 36,732
Six Months Ended June 30, 2022:			
Beginning balance	$ (7,771)	$ —	$ (7,771)
Total gains or (losses) (realized/unrealized):			
Included in regulatory assets/liabilities	7,695	—	7,695
Settlements	(2,213)	—	(2,213)
Ending balance as of June 30, 2022	$ (2,289)	$ —	$ (2,289)

(1) There were no purchases, issuances or transfers from other categories of any derivatives instruments during the periods presented in the table above.

NOTE 13. COMMON STOCK

The Company issued common stock for total net proceeds of $29.6 million and $59.5 million during the three and six months ended June 30, 2023, respectively. Most of these issuances came through the Company's sales agency agreements under which the Company may offer and sell new shares of common stock through its sales agents from time to time. Under these sales agency agreements, the Company issued 0.8 million and 1.5 million shares during the three and six months ended June 30, 2023.

NOTE 14. ACCUMULATED OTHER COMPREHENSIVE LOSS

Accumulated other comprehensive loss, net of tax, consisted of the following as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023	December 31, 2022
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $557 and $547, respectively	$ 2,095	$ 2,058

The following table details the reclassifications out of accumulated other comprehensive loss to net income by component for the three and six months ended June 30 (dollars in thousands):

	Amounts Reclassified from Accumulated Other Comprehensive Loss			
	Three months ended June 30,		Six months ended June 30,	
Details about Accumulated Other Comprehensive Loss Components (Affected Line Item in Statement of Income)	2023	2022	2023	2022
Amortization of defined benefit pension and postretirement benefit items				
Amortization of net prior service cost (1)	$ (140)	$ (200)	$ (280)	$ (400)
Amortization of net loss (1)	1,177	1,809	2,549	3,847
Adjustment due to effects of regulation (1)	(1,061)	(1,263)	(2,316)	(2,752)
Total before tax (2)	(24)	346	(47)	695
Tax expense (2)	5	(73)	10	(146)
Net of tax (2)	$ (19)	$ 273	$ (37)	$ 549

(1) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 7 for additional details).

(2) Description is also the affected line item on the Condensed Consolidated Statement of Income.

NOTE 15. EARNINGS PER COMMON SHARE

The following table presents the computation of basic and diluted earnings per common share for the three and six months ended June 30 (in thousands, except per share amounts):

	Three months ended June 30,		Six months ended June 30,	
	2023	2022	2023	2022
Numerator:				
Net income	$ 17,484	$ 11,453	$ 72,329	$ 83,018
Denominator:				
Weighted-average number of common shares outstanding-basic	75,983	72,624	75,576	72,205
Effect of dilutive securities:				
Performance and restricted stock awards	148	34	127	89
Weighted-average number of common shares outstanding-diluted	76,131	72,658	75,703	72,294
Earnings per common share:				
Basic	$ 0.23	$ 0.16	$ 0.96	$ 1.15
Diluted	$ 0.23	$ 0.16	$ 0.96	$ 1.15

There were no shares excluded from the calculation because they were antidilutive.

NOTE 16. 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 ultimate outcome of any matter because litigation and other contested proceedings are inherently 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 incurred costs through the ratemaking process.

Boyds Fire (State of Washington Department of Natural Resources (DNR) 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 $4.4 million for fire suppression and investigation costs and related expenses incurred in connection with a wildfire that occurred in Ferry County, Washington in August 2018. Specifically, the complaint alleges the fire, which became known as the "Boyds Fire," was caused by a dead ponderosa pine tree falling into an overhead distribution line, and

Avista Corp. was negligent in failing to identify and remove the tree before it came into contact with the line. Avista Corp. disputes that the tree in question was the cause of the fire and that it was negligent in failing to identify and remove it. Additional lawsuits were subsequently filed by private landowners seeking property damages, and holders of insurance subrogation claims seeking recovery of insurance proceeds paid.

The lawsuits were filed in the Superior Court of Ferry County, Washington. The Company continues to vigorously defend itself in the litigation. 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.

Road 11 Fire

In April 2022, Avista Corp. received a notice of claim from property owners seeking damages of $5 million in connection with a fire that occurred in Douglas County, Washington, in July 2020. In June 2022, those claimants filed suit in the Superior Court of Douglas County, Washington, seeking unspecified damages. The fire, which was designated as the “Road 11 Fire,” occurred in the vicinity of an Avista Corp. 115kv line, resulting in damage to three overhead transmission structures. The fire occurred during a high wind event and grew to 10,000 acres before being contained. The Company disputes that it is liable for the fire and will vigorously defend itself in the pending legal proceeding; 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.

Labor Day 2020 Windstorm

General

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.

The Company has become aware of instances where, during the course of the storm, otherwise healthy trees and limbs, located in areas outside its maintenance right-of-way, broke under the extraordinary wind conditions and caused damage to its energy delivery system at or near what is believed to be the potential area of origin of a wildfire. Those instances include what has been referred to as: the Babb Road fire (near Malden and Pine City, Washington); the Christensen Road fire (near Airway Heights, Washington); the Mile Marker 49 fire (near Orofino, Idaho); and the Kewa Field Fire (near Colville, Washington). These wildfires covered, in total, more than 25,000 acres. The Company estimates approximately 230 residential, commercial and other structures were impacted. With respect to the Christensen Road Fire, the Mile Marker 49 Fire, and the Kewa Field Fire, the Company’s investigation determined the primary cause of the fires was extreme high winds. To date, the Company has not found any evidence that the fires were caused by any deficiencies in its equipment, maintenance activities or vegetation management practices. See further discussion below regarding the Babb Road Fire.

In addition to the instances identified above, the Company is aware of a 5-acre fire that occurred in Colfax, Washington, which damaged several residential structures. The Company's investigation determined that the Company's facilities were not involved in the ignition of this fire.

The Company’s investigation has found no evidence of negligence with respect to any of the fires, and the Company will vigorously defend itself against any claims for damages that may be asserted against it with respect to the wildfires arising out of the extreme wind event; 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.

Babb Road Fire

In May 2021 the Company learned the Washington Department of Natural Resources (DNR) had completed its investigation and issued a report on the Babb Road Fire. The Babb Road fire covered approximately 15,000 acres and destroyed approximately 220 structures. There are no reports of personal injury or death resulting from the fire.

The DNR report concluded, among other things, that

- the fire was ignited when a branch of a multi-dominant Ponderosa Pine tree was broken off by the wind and fell on an Avista Corp. distribution line;
- the tree was located approximately 30 feet from the center of Avista Corp.'s distribution line and approximately 20 feet beyond Avista Corp.'s right-of-way;
- the tree showed some evidence of insect damage, damage at the top of the tree from porcupines, a small area of scarring where a lateral branch/leader (LBL) had broken off in the past, and some past signs of Gall Rust disease.

The DNR report concluded as follows: "It is my opinion that because of the unusual configuration of the tree, and its proximity to the powerline, a closer inspection was warranted. A nearer inspection of the tree should have revealed the cut LBL ends and its previous failure, and necessitated determination of the failure potential of the adjacent LBL, implicated in starting the Babb Road Fire."

The DNR report acknowledged that, other than the multi-dominant nature of the tree, the conditions mentioned above would not have been easily visible without close-up inspection of, or cutting into, the tree. The report also acknowledged that, while the presence of multiple tops would have been visible from the nearby roadway, the tree did not fail at a v-fork due to the presence of multiple tops. The Company contends that applicable inspection standards did not require a closer inspection of the otherwise healthy tree, nor was the Company negligent with respect to its maintenance, inspection or vegetation management practices.

Nine lawsuits seeking unspecified damages have been filed in connection with the Babb Road fire. Asplundh Tree Company and CNUC Utility Consulting, which both perform vegetation management services as independent contractors to the Company, have since been added as additional defendants in each of the lawsuits. The lawsuits include six subrogation actions filed by insurance companies seeking recovery for amounts paid to insureds; two actions on behalf of individual plaintiffs; and a class action lawsuit. All proceedings were consolidated for discovery and pre-trial proceedings, are pending in the Superior Court of Spokane County Washington under the lead action *Blakely v. Avista Corporation et al.*, and variously assert causes of action for negligence, private nuisance, trespass and inverse condemnation (a theory of strict liability).

On September 16, 2022, the Company filed a motion in the Superior Court of Spokane County, Washington, seeking dismissal of the Plaintiffs' inverse condemnation claims as a matter of law on the grounds that they are not legally cognizable under Washington law. On October 14, 2022, the Superior Court heard oral argument on that motion. The Court concluded the Company's motion involved mixed questions of law and fact, and, as a consequence, could not be granted at that stage of the proceedings; however, the Court indicated the Company could bring the issue before the Court again after discovery is completed.

The Company will 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.

Colstrip

Colstrip Owners Arbitration and Litigation

Colstrip Units 3 and 4 are 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 and 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 and 4 also own undivided interests in facilities common to both Units 3 and 4, as well as in certain facilities common to all four Colstrip units.

The Washington Clean Energy Transformation Act (CETA), among other things, imposes 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 is electricity from such resources, including Colstrip, may no longer be delivered to Washington retail customers after 2025.

The co-owners of Colstrip Units 3 and 4 have differing needs for the generating capacity of these units. Accordingly, certain business disagreements have arisen among the co-owners, including, disagreements as to the requirements for shutting down these units. NorthWestern has initiated arbitration pursuant to the O&O Agreement to resolve these business disagreements, and two actions have been initiated to compel arbitration of those disputes: one by Talen in the Montana Thirteenth Judicial District Court for Yellowstone County, and one by the Western Co-Owners, which is pending in Montana Federal District Court. In light of the ownership transfer agreements discussed below, the Colstrip owners agreed to stay both the litigation and the arbitration through September 29, 2023, at which time the proceedings would resume absent further agreement between the owners.

Agreement Between Talen Energy and Puget Sound Energy

In September 2022, the Company received notice that PSE and Talen entered into an agreement through which PSE has agreed to transfer its 25 percent ownership in Colstrip Units 3 and 4 to Talen at the end of 2025. The terms and conditions of the agreement are similar in most respects to the NorthWestern Transaction discussed below.

Agreement Between Avista and NorthWestern

On January 16, 2023, the Company entered into an agreement with NorthWestern under which the Company will transfer its 15 percent ownership in Colstrip Units 3 and 4 to NorthWestern. There is no monetary exchange included in the transaction. The transaction is scheduled to close on December 31, 2025 or such other date as the parties mutually agree upon.

Under the agreement, the Company will remain 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) except for certain costs relating to post-closing activities, site remediation expenses. In addition, the Company would enter into an agreement under which it would retain its voting rights with respect to decisions relating to remediation.

The Company will retain its Colstrip transmission system assets, which are excluded from the transaction.

Under the Colstrip O&O Agreement, each of the other owners of Colstrip has a 90-day period in which to evaluate the transaction and determine whether to exercise their respective rights of first refusal as to a portion of the generation being turned over to NorthWestern. That period was extended, by agreement of the Owners, through September 29, 2023.

The transaction is subject to the satisfaction of customary closing conditions including the receipt of any required regulatory approvals, as well as NorthWestern's ability to enter into a new coal supply agreement by December 31, 2024.

The Company does not expect this transaction to have a material impact on its financial results.

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 allege a failure to contain coal dust in connection with the operation of Colstrip, and seek unspecified damages. The Company will vigorously defend itself in the litigation, but at this time is unable to predict the outcome, nor an amount or range of potential impact in the event of an outcome adverse to the Company’s interests.

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. In the second, the Montana Federal District Court vacated a decision by the federal Office of Surface Mining Reclamation and Enforcement approving expansion of the mine into a new area, pending further analysis of potential environmental impact. Both decisions have been appealed. Avista Corp. is not a party to either of these proceedings, but is continuing to monitor the progress of both lawsuits and assess the impact, if any, of the proceedings on Westmoreland’s ability to meet its contractual coal supply obligations.

National Park Service (NPS) - Natural and Cultural Damage Claim

In March 2017, the Company accessed property managed by the National Park Service (NPS) to prevent the imminent failure of a power pole surrounded by flood water in the Spokane River. The Company voluntarily reported its actions to the NPS several days later. Thereafter, in March 2018, the NPS notified the Company that it might seek recovery for unspecified costs and damages allegedly caused during the incident pursuant to the System Unit Resource Protection Act (SURPA), 54 U.S.C. 100721 et seq. In January 2021, the United States Department of Justice (DOJ) requested the Company and the DOJ renew discussions relating to the matter. In July 2021, the DOJ communicated that it may seek damages of approximately $2 million in connection with the incident for alleged damage to “natural and cultural resources”. In addition, the DOJ indicated that it may seek treble damages under the SURPA and state law, bringing its total potential claim to approximately $6 million.

The Company disputes the position taken by the DOJ with respect to the incident, as well as the nature and extent of the DOJ’s alleged damages, and will vigorously defend itself in any litigation that may arise with respect to the matter. The Company and the DOJ have engaged in discussions to understand their respective positions and determine whether a resolution of the dispute may be possible. However, the Company cannot predict the outcome of the matter.

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. On January 23, 2023, the Company was served with a lawsuit filed in the District Court of Kootenai County, Idaho by one property owner, seeking unspecified damages. The Company intends to vigorously defend itself in this action.

Climate Commitment Act (CCA) Obligations

Effective January 1, 2023, the CCA went into effect in the State of Washington, requiring the Company to secure enough carbon allowances to cover its carbon emissions over a certain amount each year. The state has issued carbon allowances to cover electric retail sales. In May 2023, a model was approved for use in calculating the allowances needed for compliance which assumes hydroelectric generation is first used for wholesale sales, therefore reducing allowances required for wholesale sales. The Company expects to recover any costs incurred for its Washington operations through the ratemaking process.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes any ultimate 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. See "Note 22 of the Notes to Consolidated Financial Statements" in the 2022 Form 10-K for additional discussion regarding other contingencies.

NOTE 17. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. The Company's management evaluates performance based on income (loss) from operations before income taxes as well as net income (loss). 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, as it has separate financial reports reviewed in detail by the Chief Operating Decision Maker and its operations and risks are sufficiently different from Avista Utilities and the other businesses at AERC that it cannot be aggregated with any 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.

The following table presents information for each of the Company's business segments (dollars in thousands):

	Avista Utilities	Alaska Electric Light and Power Company	Total Utility	Other	Intersegment Eliminations (1)	Total
For the three months ended June 30, 2023:						
Operating revenues	$ 368,604	$ 11,194	$ 379,798	$ 139	$ —	$ 379,937
Resource costs	140,017	1,227	141,244	—	—	141,244
Other operating expenses	99,276	3,795	103,071	749	—	103,820
Depreciation and amortization	63,419	2,729	66,148	—	—	66,148
Income (loss) from operations	41,257	3,161	44,418	(610)	—	43,808
Interest expense (2)	34,044	1,452	35,496	448	(318)	35,626
Income taxes	(5,556)	473	(5,083)	(727)	—	(5,810)
Net income (loss)	18,810	1,359	20,169	(2,685)	—	17,484
Capital expenditures (3)	121,834	4,422	126,256	—	—	126,256
For the three months ended June 30, 2022:						
Operating revenues	$ 368,515	$ 9,906	$ 378,421	$ 145	$ —	$ 378,566
Resource costs	156,221	1,176	157,397	—	—	157,397
Other operating expenses	100,782	3,700	104,482	2,910	—	107,392
Depreciation and amortization	60,106	2,700	62,806	30	—	62,836
Income (loss) from operations	25,037	2,041	27,078	(2,795)	—	24,283
Interest expense (2)	27,078	1,487	28,565	137	(7)	28,695
Income taxes	(2,565)	(211)	(2,776)	1,777	—	(999)
Net income	3,950	771	4,721	6,732	—	11,453
Capital expenditures (3)	111,850	2,809	114,659	342	—	115,001
For the six months ended June 30 2023:						
Operating revenues	$ 828,746	$ 25,557	$ 854,303	$ 265	$ —	$ 854,568
Resource costs	332,154	2,018	334,172	—	—	334,172
Other operating expenses	200,665	7,384	208,049	1,760	—	209,809
Depreciation and amortization	125,883	5,453	131,336	31	—	131,367
Income (loss) from operations	111,816	10,119	121,935	(1,526)	—	120,409
Interest expense (2)	68,118	2,904	71,022	795	(536)	71,281
Income taxes	(13,504)	2,012	(11,492)	(946)	—	(12,438)
Net income (loss)	70,437	5,401	75,838	(3,509)	—	72,329
Capital expenditures (3)	219,598	7,148	226,746	3	—	226,749
For the six months ended June 30 2022:						
Operating revenues	$ 817,387	$ 22,960	$ 840,347	$ 265	$ —	$ 840,612
Resource costs	342,645	1,620	344,265	—	—	344,265
Other operating expenses	191,766	7,243	199,009	3,866	—	202,875
Depreciation and amortization	119,985	5,398	125,383	62	—	125,445
Income (loss) from operations	102,816	8,099	110,915	(3,663)	—	107,252
Interest expense (2)	53,650	2,974	56,624	265	(10)	56,879
Income taxes	(14,925)	1,049	(13,876)	2,041	—	(11,835)
Net income	71,228	4,064	75,292	7,726	—	83,018
Capital expenditures (3)	207,314	3,332	210,646	756	—	211,402
Total Assets:						
As of June 30, 2023:	$ 6,929,611	$ 270,774	$ 7,200,385	$ 189,314	$ (18,384)	$ 7,371,315
As of December 31, 2022:	$ 6,976,164	$ 264,322	$ 7,240,486	$ 187,027	$ (10,163)	$ 7,417,350

(1) Intersegment eliminations reported as interest expense represent intercompany interest.

(2) Including interest expense to affiliated trusts.

(3) The capital expenditures for the other businesses are included in other investing activities on the Condensed Consolidated Statements of Cash Flows.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of
Avista Corporation

Results of Review of Interim Financial Information

We have reviewed the accompanying condensed consolidated balance sheet of Avista Corporation and subsidiaries (the "Company") as of June 30, 2023, the related condensed consolidated statements of income, comprehensive income, equity for the three-month and six-month periods ended June 30, 2023 and 2022, and of cash flows for the six-month periods ended June 30, 2023 and 2022 and the related notes (collectively referred to as the "interim financial information"). Based on our reviews, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of the Company as of December 31, 2022, and the related consolidated statements of income, comprehensive income, equity, and cash flows for the year then ended (not presented herein); and in our report dated February 21, 2023, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2022, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

Basis for Review Results

This interim financial information is the responsibility of the Company's management. 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 reviews in accordance with standards of the PCAOB. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the PCAOB, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

/s/ Deloitte & Touche LLP

Portland, Oregon

August 1, 2023

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

Management’s Discussion and Analysis of Financial Condition and Results of Operations was prepared in accordance with the SEC’s Regulation S-K for interim financial information and with the instructions to Form 10-Q. This Management’s Discussion and Analysis of Financial Condition and Results of Operations does not contain the full detail or analysis, or the full discussion of trends and uncertainties, that would accompany financial statements for a full fiscal year; therefore, it should be read in conjunction with the Company's 2022 Form 10-K.

Business Segments

Our business segments have not changed during the six months ended June 30, 2023. See the 2022 Form 10-K as well as “Note 17 of the Notes to Condensed Consolidated Financial Statements” for further information regarding our business segments.

The following table presents net income (loss) for each of our business segments (and the other businesses) for the three and six months ended June 30 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2023	2022	2023	2022
Avista Utilities	$ 18,810	$ 3,950	$ 70,437	$ 71,228
AEL&P	1,359	771	5,401	4,064
Other	(2,685)	6,732	(3,509)	7,726
Net income	$ 17,484	$ 11,453	$ 72,329	$ 83,018

Executive Overview

Overall Results

Net income for the three months ended June 30, 2023 increased compared to the three months ended June 30, 2022, primarily due to Avista Utilities results, including increased utility margin and increased income tax benefits. Utility margin increased due to customer growth and the effect of general rate cases, as well as decreased net costs under the ERM, which resulted in a $1.0 million pre-tax benefit compared to a $4.8 million pre-tax expense in the second quarter of 2022. These increases were partially offset by an increase in interest expense, resulting from increased borrowings outstanding during the period as well as increased interest rates compared to the second quarter of 2022, as well as investment losses recorded by our other businesses compared to gains recorded in 2022.

Net income for the six months ended June 30, 2023 decreased compared to the six months ended June 30, 2022 primarily due to increased interest expense resulting from increased borrowings outstanding during the period as well as increased interest rates compared to the second quarter of 2022, as well as increased operating costs. We also recorded investment losses for our other businesses compared to gains recorded in 2022. These were partially offset by an increase in utility margin, resulting from customer growth and the effects of general rate cases.

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

2023 Hydroelectric Generation

In May and June of 2023, our region experienced historically high temperatures, causing the snowpack to melt more rapidly than expected. The quick runoff had a significant negative impact on our hydrogeneration resources, resulting in this being one of our worst years for hydroelectric generation. As a result, we increased thermal generation and purchased power to compensate for the decrease in available hydroelectric generation, and our ability to optimize our generation assets has been limited compared to the opportunities we had originally anticipated for the year. The decreased hydroelectric generation availability compared to our expectations has a significant impact on the ERM in Washington, as well as our financial results.

Washington Climate Commitment Act (CCA)

Effective January 1, 2023, the CCA went into effect in the State of Washington, requiring us to secure enough carbon allowances to cover our carbon emissions over a certain amount each year. See "Environmental Issues and Contingencies" below for further discussion of the CCA and expected impacts to our financial results.

Inflation

Although we continue to experience inflationary pressures in multiple areas of our business, inflation has eased considerably compared to the same period last year. Nevertheless, inflation remains above the Federal Reserve's target and we cannot estimate how long inflation will remain at elevated levels. In addition, our interest costs increased due to higher interest rates than those approved in our most recent general rate cases, resulting in increased interest expense.

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, as experienced in 2022 and which are continuing into 2023. While we believe our recent general rate settlements are helpful, some increases in our operating expenses and interest costs will have to be addressed in future rate cases. See “Regulatory Matters” for additional discussion of the general rate cases.

Climate Change

There is a trend of increasing average temperatures that has had, and will likely continue to have, various direct and indirect impacts on our business. Direct impacts 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 and the resulting impact on the availability of hydroelectric resources at times of peak demand. Indirect impacts include, without limitation, federal, state and local legislation or regulation (in effect and proposed) that limits (or eliminates) the use of fossil-fuel for electric generation, as well as the use of natural gas for heating in residential and commercial buildings.

For additional information regarding climate change, effects of climate change on our operations and results of operations and legislation and regulation designed to mitigate climate change, see "Environmental Issuance and Contingencies" and our 2022 Form 10-K.

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 expect to 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.

With regards to the timing and plans for future filings, 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

2022 General Rate Cases

On December 12, 2022, the WUTC issued an order approving the multi-party settlement agreement filed in June 2022. The parties to the settlement agreement included, in addition to us, the Staff of the WUTC, the Alliance of Western Energy Consumers, the NW Energy Coalition, The Energy Project, Walmart, Small Business Utility Advocates and Sierra Club. The Public Counsel Unit of the Washington Attorney General's Office (Public Counsel), while a party to the rate cases, did not join in the settlement agreement. The settlement agreement was reached after negotiation of all issues but is "results-focused" -- that is, it represents agreement among all parties (except Public Counsel) as to our overall revenue requirement, without specifying the details of any component except the rate of return on rate base.

The approved rates were designed to increase annual base electric revenues by $38.0 million (or 6.9 percent), effective in December 2022, and $12.5 million (or 2.1 percent), effective in December 2023. The approved rates were also designed to increase annual base natural gas revenues by $7.5 million (or 6.5 percent), effective in December 2022, and $1.5 million (or 1.2 percent), effective in December 2023.

To mitigate the overall impact of the revenue increases on customers, we offset part of the 2022 base rate request with tax customer credits. The total estimated benefits of these credits, $27.6 million for electric customers and $12.5 million for natural gas customers, will be returned over a two-year period from December 2022 to December 2024.

In addition, the order approved a separate tracking mechanism and tariff for purposes of recovering existing and prospective Colstrip costs.

The WUTC approved an ROR on rate base of 7.03 percent, but the settlement does not specify an explicit ROE, cost of debt or capital structure.

These general rate cases require a subsequent review of capital projects included in rates and a refund of revenues related to imprudent expenditures or those not used and useful.

2024 General Rate Cases

The Company expects to file its next Washington electric and natural gas general rate cases in the first quarter of 2024.

Idaho General Rate Cases

2023 General Rate Cases

In February 2023, we filed multiyear electric and natural gas general rate cases with the IPUC.

In June 2023, we reached a settlement agreement with the Staff of the IPUC, Clearwater Paper Corporation, Idaho Forest Group, LLC and Walmart Inc. The remaining joint party, Idaho Conservation League / NW Energy Coalition, did not join the settlement, but takes issue only with one rate design component that does not impact the proposed revenue requirement.

The proposed rates under the settlement agreement are designed to increase annual base electric revenues by $22.1 million, or 8.0 percent, effective in September 2023, and $4.3 million, or 1.4 percent, effective in September 2024. The agreement is also designed to increase annual base natural gas revenues by $1.3 million, or 2.7 percent, effective September 2023, and a negligible increase effective September 2024.

The settlement contemplates a return on equity of 9.4 percent, based on a common equity ratio of 50 percent, and a rate of return on rate base of 7.19 percent.

Ongoing capital infrastructure investment (including replacement of wood poles and natural gas distribution pipe, continued investment in the wildfire resiliency plan, and technology) is the main driver of the proposed increases.

The IPUC has up to nine months from the date of the original filing to review and issue a decision.

Oregon General Rate Cases

2023 General Rate Case

In March 2023, we filed a natural gas general rate case with the OPUC. If approved, new rates would be effective on January 1, 2024.

In May 2023, we, along with the OPUC staff and the alliance of Western Energy Consumers reached a partial settlement agreement, agreeing to a ROR of 7.24 percent, an ROE of 9.5 percent, and a common equity ratio of 50 percent.

After incorporating the settlement agreement, the proposed increase in annual base natural gas revenues still subject to further regulatory process is $9.4 million (or 12.3 percent).

Ongoing capital infrastructure investment (including replacement and expansion of natural gas distribution pipe and technology) is the main driver of the proposed increase.

The OPUC has up to ten months from the date of the original filing to review and issue a decision.

AEL&P

Alaska General Rate Case

In July 2022, AEL&P filed an electric general rate case with the Regulatory Commission of Alaska (RCA). AEL&P received approval in August 2022 for an interim base rate increase of 4.5 percent (designed to increase annual electric revenues by $1.6 million), which took effect in September 2022. AEL&P also requested a permanent base rate increase of an additional 4.5 percent (designed to increase annual electric revenues by $1.6 million), which, if approved, could take effect in October 2023. The proposed revenue increase request is based on a 13.45 percent ROE with a common equity ratio of 60.7 percent and a ROR of 10.0 percent.

The RCA must rule on permanent rate increases within 450 days (approximately 15 months) from the date of filing.

Avista Utilities

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to customers with no change in utility margin (operating revenues less resource costs) or net income. In Oregon, we absorb (cost or benefit) 10 percent of the difference between actual and projected natural gas costs included in retail rates for supply that is not hedged. Total net deferred natural gas costs among all jurisdictions were assets of $84.0 million and $52.1 million as of June 30, 2023 and December 31, 2022, respectively.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between actual power supply costs, net of the margin on wholesale sales of energy and sales of fuel, and the amount included in base retail rates for our Washington customers. See the 2022 Form 10-K for a full discussion of the mechanics of the ERM and the various customer/Company sharing bands. Total net deferred power costs under the ERM were assets of $33.3 million and $30.5 million as of June 30, 2023 and December 31, 2022, respectively. These deferred power cost balances represent amounts due from customers. Pursuant to WUTC requirements, should the cumulative deferral balance exceed $30 million in the rebate or surcharge direction, we must make a filing with the WUTC to adjust customer rates to either return the balance to customers or recover the balance from customers. In June 2023, we received approval from the WUTC for a rate surcharge to customers over a two-year period, commencing July 1, 2023.

The PCA mechanism in Idaho allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power supply costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were assets of $16.7 million and $16.3 million as of June 30, 2023 and December 31, 2022, respectively. These deferred power cost balances represent amounts due from customers.

Decoupling 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 our jurisdictions, 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 our decoupling mechanisms. See the 2022 Form 10-K for a discussion of the mechanisms in each jurisdiction.

Total net cumulative decoupling deferrals among all jurisdictions were regulatory liabilities of $32.6 million as of June 30, 2023 and $18.2 million as of December 31, 2022. Decoupling regulatory liabilities represent amounts due to customers.

See "Results of Operations - Avista Utilities" for further discussion of the amounts recorded to operating revenues in 2023 and 2022 related to the decoupling mechanisms.

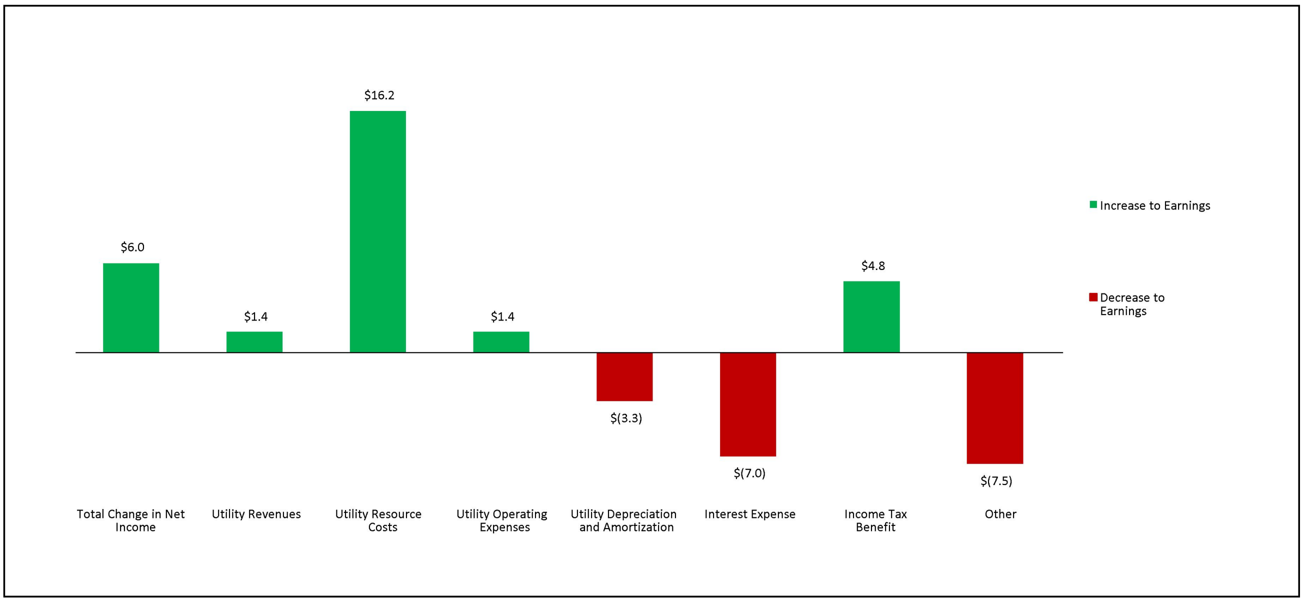
Results of Operations - Overall

The following provides an overview of changes in our Condensed 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.

The balances included below for utility operations reconcile to the Condensed Consolidated Statements of Income.

Three months ended June 30, 2023 compared to the three months ended June 30, 2022

The following graph shows the total change in net income for the second quarter of 2023 compared to the second quarter of 2022, as well as the various factors that caused such change (dollars in millions):



Utility revenues were relatively consistent between the second quarters of 2023 and 2022. While retail revenues increased primarily due to increased natural gas rates and electric usage, these increases were offset by decreased sales of fuel and natural gas wholesale activity.

Utility resource costs decreased at Avista Utilities due to decreased natural gas prices and power supply costs, partially offset by increases associated with deferrals of net power supply costs below authorized levels.

Utility operating expenses slightly decreased when compared to the second quarter of 2022, primarily a result of the 2022 write-off of $4.0 million related to the Dry Ash Disposal System at Colstrip as part of the 2022 Washington general rate case. This was offset by inflationary pressures resulting in increased labor costs. See the "Executive Overview" for further discussion of inflation.

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

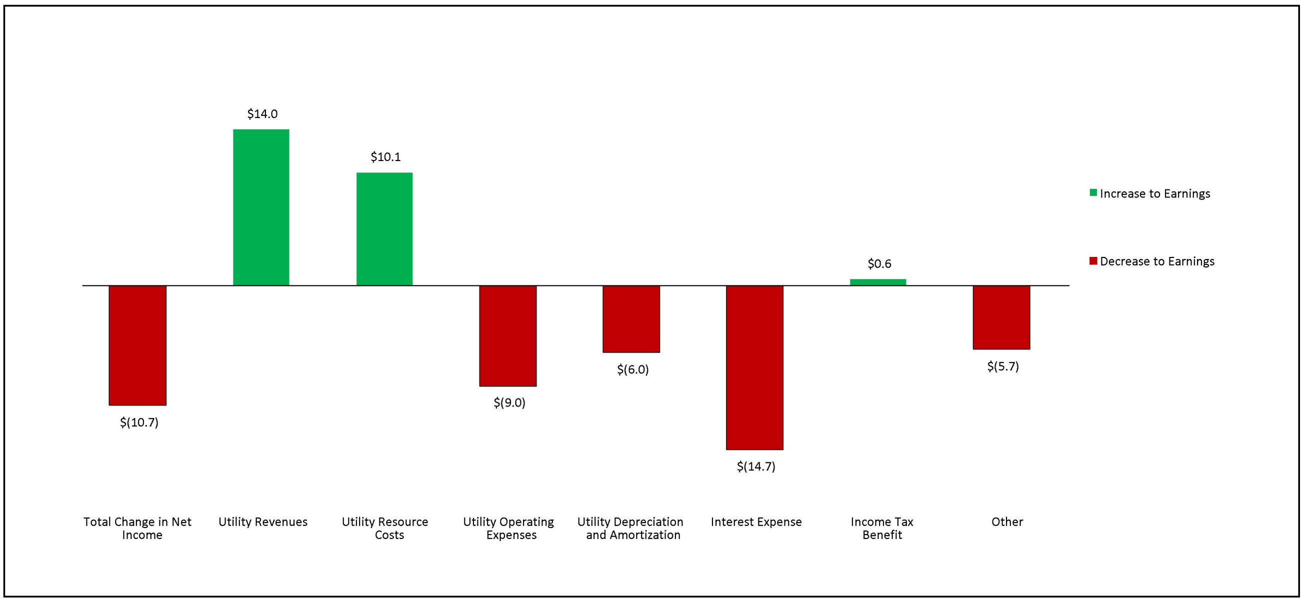
Interest expense increased due to higher interest rates associated with inflation, as well as increased borrowings outstanding. Borrowings increased due to capital expenditures, higher energy commodity prices and additional requirements for cash collateral. See the "Executive Overview" for further discussion of inflation.

Income tax benefit increased primarily due to increased tax customer credits offsetting the bill impact of rate increases included in our 2022 Washington general rate cases, partially offset by the timing impact of spreading the increased credits over the year as a percentage of pre-tax income based on the estimated annual effective tax rate. See "Note 8 of the Notes to Condensed Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

The decrease in other was primarily related to investment losses recognized in 2023, compared to investment gains in 2022. This was partially offset by increased interest income and decreased other non-utility operating expenses.

Six months ended June 30, 2023 compared to the six months ended June 30, 2022

The following graph shows the total change in net income for the second quarter of 2023 compared to the second quarter of 2022, as well as the various factors that caused such change (dollars in millions):



Utility revenues increased at Avista Utilities when compared to the first half of 2022. This was primarily due to increased natural gas retail revenues associated with increased retail rates (primarily PGAs), particularly during the first quarter of 2023. This was partially offset by decreased natural gas wholesale revenues and financial losses on our derivative contracts, which are netted with utility revenues.

Utility resource costs decreased at Avista Utilities due to financial gains related to our hedging activities that are netted with our expenses, as well as deferred costs in excess of authorized levels during the first quarter of 2023. These decreases were partially offset by increases in purchased power prices during the period, as well as increased natural gas prices during the first quarter.

Utility operating expenses increased when compared to the first half of 2022, primarily due to inflationary pressures resulting in increased labor costs, as well as increased net amortizations of previously deferred costs. See the "Executive Overview" for further discussion of inflation.

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

Interest expense increased due to higher interest rates associated with inflation, as well as increased borrowings outstanding. Borrowings increased due to capital expenditures, higher energy commodity prices and additional requirements for cash collateral. See the "Executive Overview" for further discussion of inflation.

Income tax benefit decreased primarily due the tax customer credits offsetting the bill impact of rate increases included in our 2021 Washington and Idaho general rate cases. These tax credits will be fully returned to customers by the end of the third quarter of 2023 and will no longer reduce both customer bills and income tax expense. Income tax is spread throughout the year as a percentage of pre-tax income based on the estimated annual effective tax rate, and as a result the benefit has decreased compared to the prior year. See "Note 8 of the Notes to Condensed Consolidated Financial Statements" for further details and a reconciliation of our effective tax rate.

The decrease in other was primarily related to investment losses recognized in 2023, compared to investment gains in 2022. This was partially offset by increased interest income and decreased other non-utility operating expenses.

Non-GAAP Financial Measures

The following discussion for Avista Utilities includes two financial measures considered “non-GAAP financial measures”: electric utility margin and natural gas utility margin. In the AEL&P section, we include a discussion of utility margin, which is also a non-GAAP financial measure.

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 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 17 of the Notes to Condensed Consolidated Financial Statements."

The presentation of electric utility margin and natural gas utility margin is intended to enhance the understanding of 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 business has different cost sources, cost recovery mechanisms and jurisdictions, so we believe 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.

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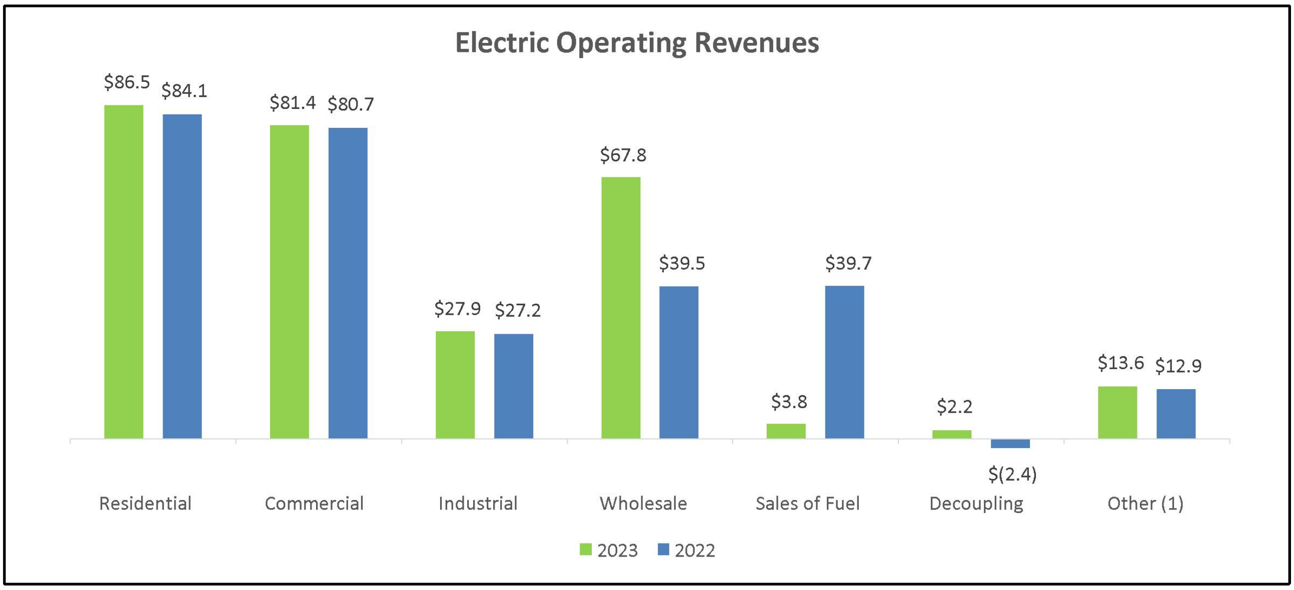
Results of Operations - Avista Utilities

Three months ended June 30, 2023 compared to the three months ended June 30, 2022

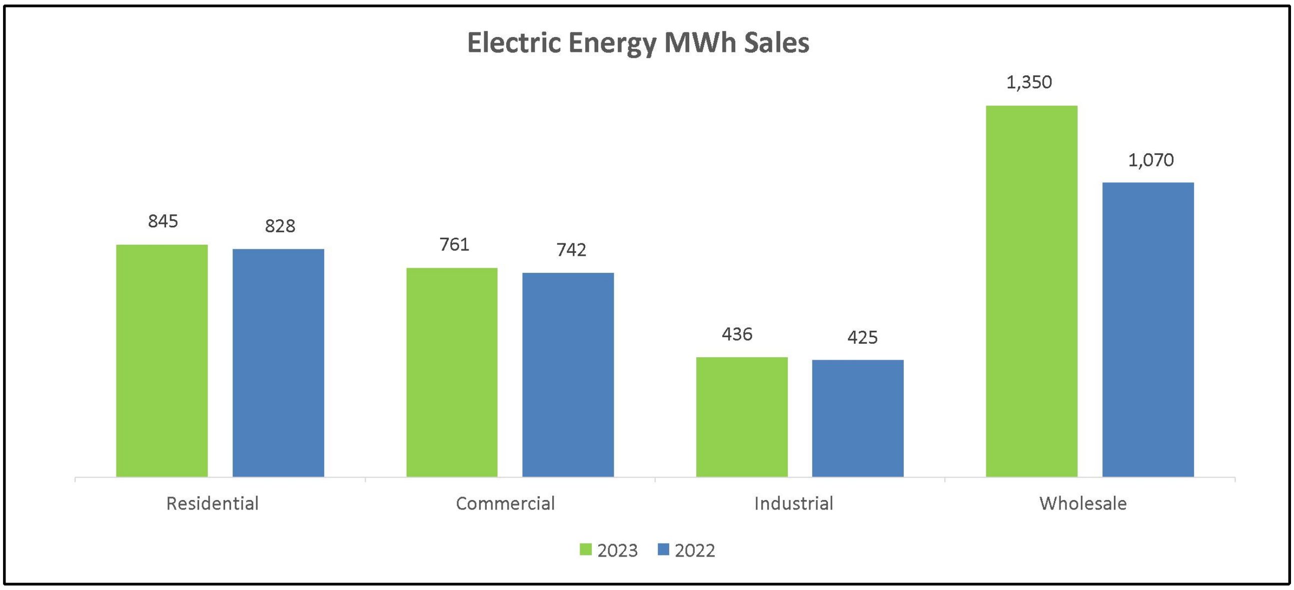
Utility Operating Revenues

The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the three months ended June 30, 2023 and 2022 (dollars in millions and MWhs in thousands):



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues.

Total electric operating revenues in the graph above include intracompany sales of $2.1 million and $4.2 million for the three months ended June 30, 2023 and 2022, respectively.



The following table presents the current year deferrals and the amortization of prior year decoupling balances reflected in utility electric operating revenues for the three months ended June 30 (dollars in thousands):

	Electric Decoupling Revenues	
	2023	2022
Current year decoupling deferrals (a)	$ 476	$ 708
Amortization of prior year decoupling deferrals (b)	1,755	(3,062)
Total electric decoupling revenue	$ 2,231	$ (2,354)

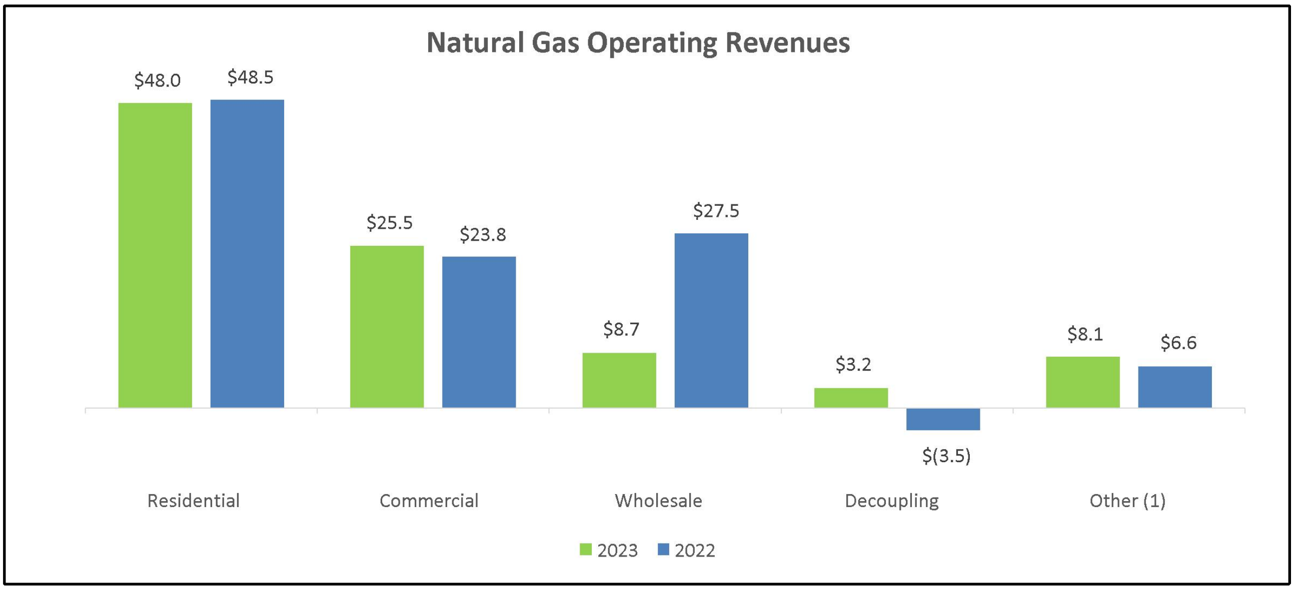
(a) Positive amounts are increases in decoupling revenue in the current year and will be surcharged to customers in future years. Negative amounts are decreases in decoupling revenue in the current year and will be rebated to customers in future years.

(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 $1.5 million for the second quarter of 2023 as compared to the second quarter of 2022. The primary changes that occurred during the period were as follows:

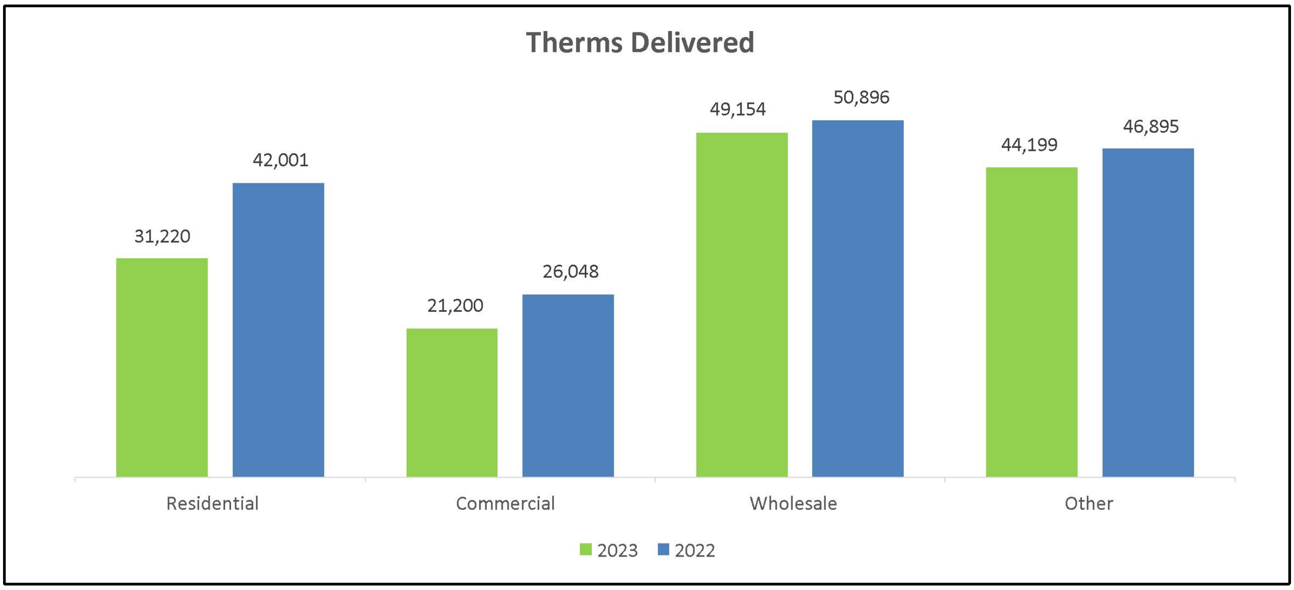
- a $3.8 million increase in retail electric revenue due to an increase in MWhs sold (increased revenues by $4.4 million) partially offset by a decrease in retail rates (decreased revenues by $0.6 million).
- a $28.3 million increase in wholesale electric revenues due to an increase in sales prices (increased revenues $14.2 million) and an increase in sales volumes (increased revenues $14.1 million). The fluctuation of volumes was due to increased thermal generation, which allowed for additional opportunities to optimize our generation assets.
- a $35.9 million decrease in sales of fuel as part of increased thermal generation and decreased fuel resource optimization activities, including associated financial hedging activities.
- a $4.6 million increase in electric decoupling revenue, resulting from amortization of prior year rebate balances in 2023, compared to amortization of surcharge balances in 2022.

The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the three months ended June 30, 2023 and 2022 (dollars in millions and therms in thousands):



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues.

Total natural gas operating revenues in the graph above include intracompany sales of $6.0 million and $11.9 million for the three months ended June 30, 2023 and 2022, respectively.



The following table presents the current year deferrals and the amortization of prior year decoupling balances reflected in utility natural gas operating revenues for the three months ended June 30 (dollars in thousands):

	Natural Gas Decoupling Revenues	
	2023	2022
Current year decoupling deferrals (a)	$ 4,661	$ (3,235)
Amortization of prior year decoupling deferrals (b)	(1,380)	(204)
Total natural gas decoupling revenue	$ 3,281	$ (3,439)

(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 $9.4 million for the second quarter of 2023 as compared to the second quarter of 2022. The primary changes that occurred during the period were as follows:

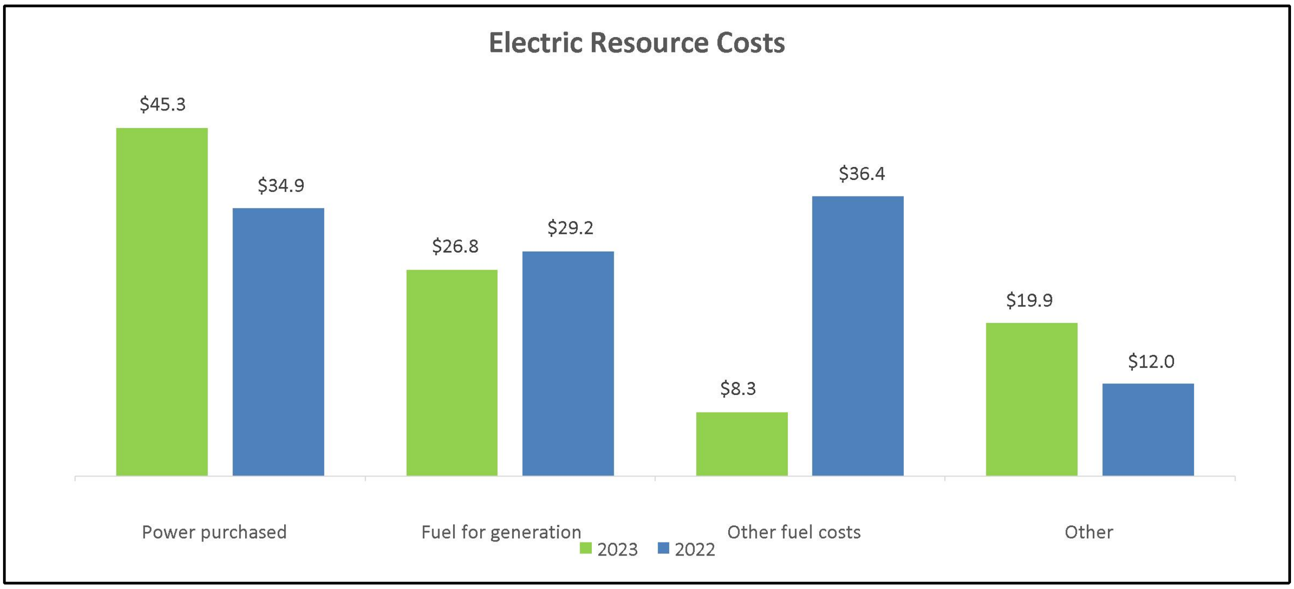
- a $3.0 million increase in natural gas retail revenues (including industrial, which is included in other) due to higher retail rates (increased revenues $22.3 million), partially offset by lower sales volumes (decreased revenues $19.3 million).
  - Retail rates increased mainly due to PGA rate increases in all jurisdictions (which do not impact utility margin).
  - Retail natural gas sales volumes decreased primarily due to lower residential and commercial usage, resulting from warmer weather (decreasing heating load). Compared to the second quarter of 2022, residential use per customer decreased 26 percent, and commercial firm use per customer decreased 20 percent. Heating degree days in Spokane were 40 percent below the prior year and 25 percent below our historical normal. Heating degree days in Medford were 30 percent below the prior year and 5 percent below our historical normal.
- an $18.8 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $18.5 million), and a decrease in sales volumes of (decreased revenues $0.3 million). Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- a $6.7 million increase in natural gas decoupling revenue primarily due to surcharges to residential customers in the second quarter of 2023 due to lower than normal usage compared to rebates in 2022, partially offset by increased amortization of surcharge balances.

The following table presents Avista Utilities' average number of electric and natural gas retail customers for the three months ended June 30, 2023 and 2022:

	Electric Customers		Natural Gas Customers	
	2023	2022	2023	2022
Residential	365,537	360,765	340,506	336,947
Commercial	45,438	44,594	37,129	36,808
Interruptible	—	—	50	44
Industrial	1,193	1,196	186	189
Public street and highway lighting	689	685	—	—
Total retail customers	412,857	407,240	377,871	373,988

Utility Resource Costs

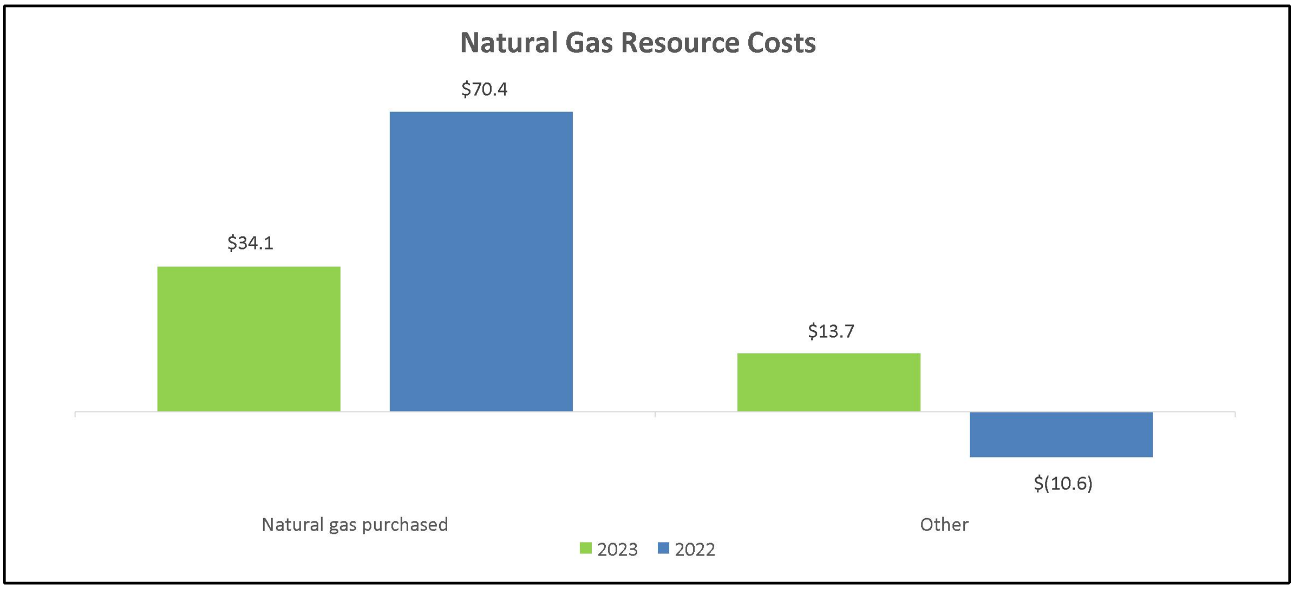
The following graphs present Avista Utilities' resource costs for the three months ended June 30, 2023 and 2022 (dollars in millions):



Total electric resource costs in the graph above include intracompany resource costs of $6.0 million and $11.9 million for the three months ended June 30, 2023 and 2022, respectively.

Total electric resource costs decreased $12.2 million for the second quarter of 2023 as compared to the second quarter of 2022. The primary changes that occurred during the period were as follows:

- a $10.4 million increase in power purchased due to an increase in the volume of power purchases (increased costs $8.7 million) and an increase in wholesale prices (increased costs $1.7 million). The change in volumes was primarily the result of fluctuations in customer loads and decreased hydroelectric generation.
- a $2.4 million decrease in fuel for generation due to decreased natural gas fuel prices, partially offset by an increase in thermal generation volumes due in part to decreased hydroelectric generation.
- a $28.1 million decrease in other fuel costs. These costs represent fuel and the related derivative instruments purchased for generation which were later sold when conditions indicated it was more economical to sell the fuel as part of the resource optimization process. When the fuel is sold either physically or through a derivative instrument, that revenue is included in sales of fuel.
- a $7.9 million increase in other electric resource costs, primarily related to an increase in deferred benefits associated with net power supply costs below authorized levels.



Total natural gas resource costs in the graph above include intracompany resource costs of $2.1 million and $4.2 million for the three months ended June 30, 2023 and 2022, respectively.

Total natural gas resource costs decreased $12.0 million for the second quarter of 2023 as compared to the second quarter of 2022 primarily due to the following:

- a $36.3 million decrease in natural gas purchased due to a decrease in the price of natural gas (decreased costs $31.1 million), and a decrease in volumes (decreased costs $5.2 million). The decrease in volumes is primarily due to decreased retail usage.
- a $24.3 million increase from net amortizations and deferrals of natural gas costs, primarily related to an increase in deferred benefits associated with net power supply costs below authorized levels.

Utility Margin

The following table reconciles Avista Utilities' operating revenues, as presented in "Note 17 of the Notes to Condensed Consolidated Financial Statements" to the Non-GAAP financial measure utility margin for the three months ended June 30, 2023 and 2022 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2023	2022	2023	2022	2023	2022	2023	2022
Operating revenues	$ 283,130	$ 281,633	$ 93,529	$ 102,919	$ (8,055)	$ (16,037)	$ 368,604	$ 368,515
Resource costs	100,291	112,480	47,781	59,778	(8,055)	(16,037)	140,017	156,221
Utility margin	$ 182,839	$ 169,153	$ 45,748	$ 43,141	$ —	$ —	$ 228,587	$ 212,294

Electric utility margin increased $13.7 million and natural gas utility margin increased $2.6 million.

Electric utility margin increased primarily due to impacts of the ERM, customer growth and the effects of general rate cases.

In the second quarter of 2023, we had a $1.0 million pre-tax benefit under the ERM in Washington, compared to a $4.8 million pre-tax expense for the second quarter of 2022.

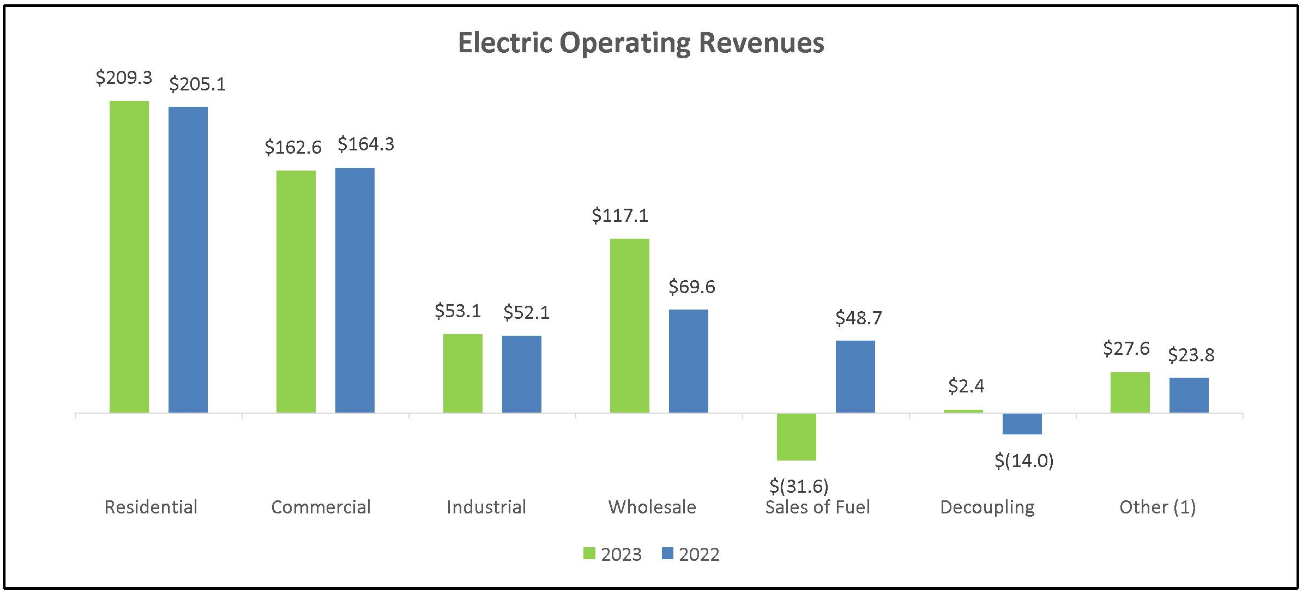
Natural gas utility margin increased primarily due to customer growth and the effects of general rate cases.

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 condensed consolidated financial statements but are included in the separate results for electric and natural gas presented above.

Six months ended June 30, 2023 compared to the six months ended June 30, 2022

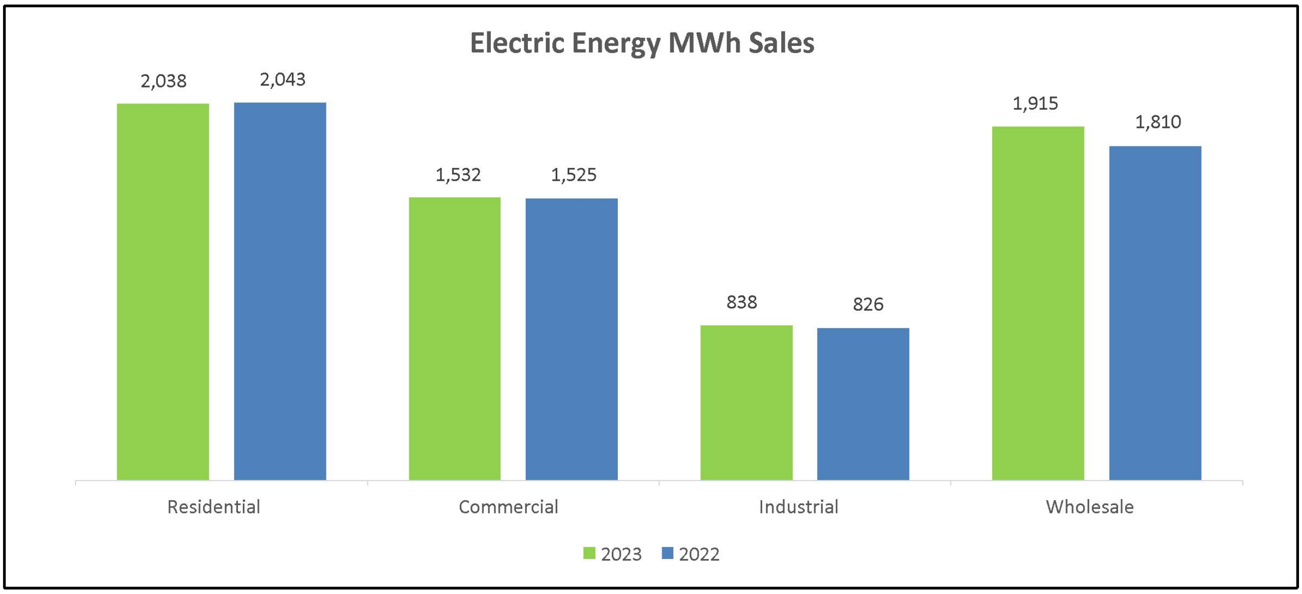
Utility Operating Revenues

The following graphs present Avista Utilities' electric operating revenues and megawatt-hour (MWh) sales for the six months ended June 30, 2023 and 2022 (dollars in millions and MWhs in thousands):



(1) This balance includes public street and highway lighting, which is considered part of retail electric revenues.

Total electric operating revenues in the graph above include intracompany sales of $3.3 million and $4.4 million for the six months ended June 30, 2023 and 2022, respectively.



The following table presents the current year deferrals and the amortization of prior year decoupling balances reflected in utility electric operating revenues for the six months ended June 30 (dollars in thousands):

	Electric Decoupling Revenues	
	2023	2022
Current year decoupling deferrals (a)	$ (2,046)	$ (8,096)
Amortization of prior year decoupling deferrals (b)	4,478	(5,885)
Total electric decoupling revenue	$ 2,432	$ (13,981)

(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.

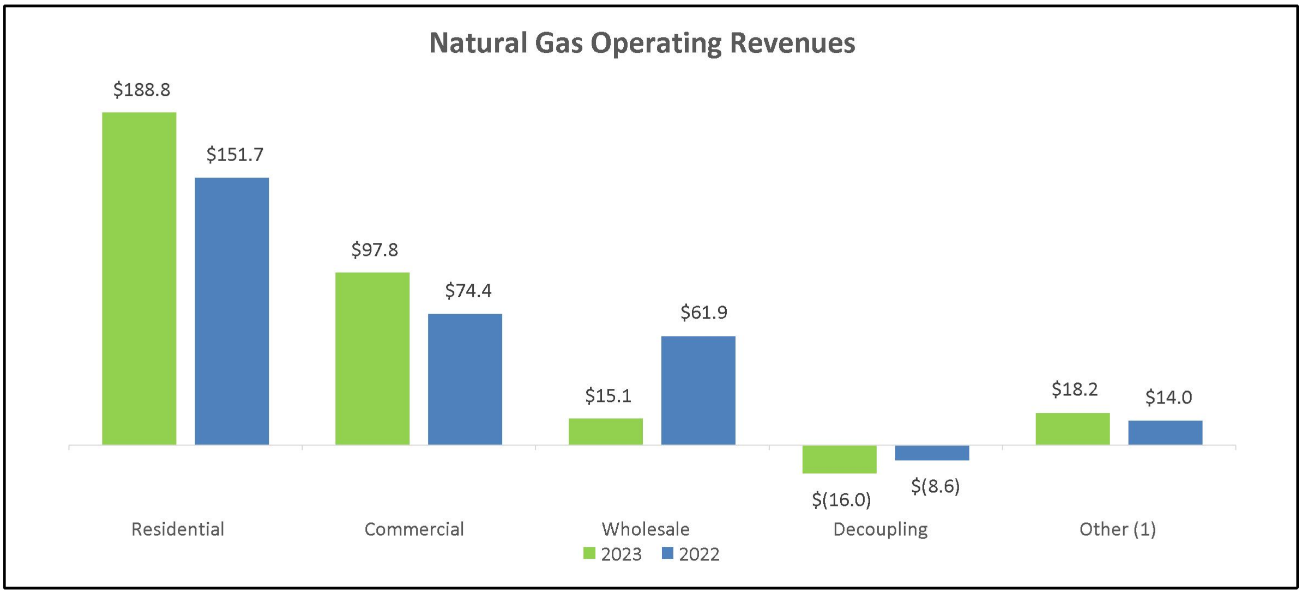
(b) Positive amounts are increases in decoupling revenue in the current year and are related to the amortization of rebate balances that resulted in prior years and are being refunded to customers (causing a corresponding decrease in retail revenue from customers) in the current year. Negative amounts 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 decreased $9.1 million for the first half of 2023 as compared to the first half of 2022. The primary changes that occurred during the period were as follows:

- a $3.6 million increase in retail electric revenue due to an increase in retail rates (increased revenues by $2.2 million), and an increase in MWhs sold (increased revenues by $1.4 million).
- a $47.5 million increase in wholesale electric revenues due to an increase in sales prices (increased revenues $41.0 million) and an increase in sales volumes (increased revenues $6.5 million). The fluctuation of volumes was due to resource optimization activities.
- an $80.3 million decrease in sales of fuel as part of thermal generation resource optimization activities, including associated financial hedging activities, which includes net losses on derivative instruments.
- a $16.4 million increase in electric decoupling revenue, resulting from decreasing rebates in 2023 resulting from lower usage from residential customers compared to the prior year, as well as amortization of prior year rebate balances in 2023, compared to amortization of surcharge balances in 2022.

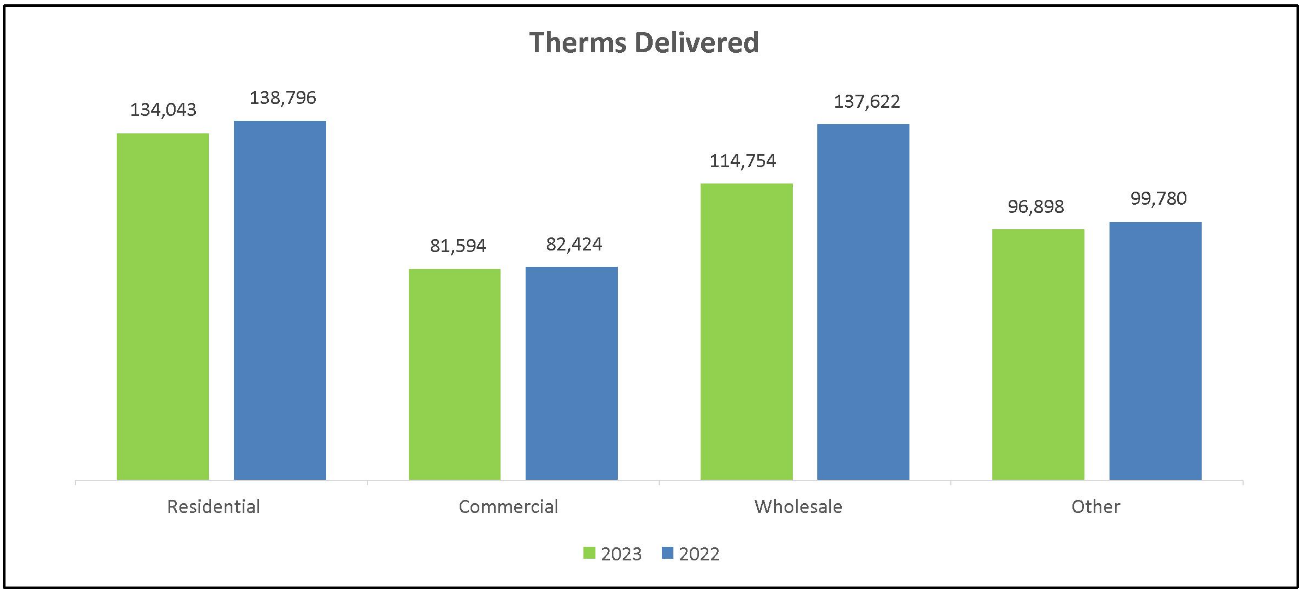
- a $3.8 million increase in other revenue, primarily due to increased transmission revenue.

The following graphs present Avista Utilities' natural gas operating revenues and therms delivered for the six months ended June 30, 2023 and 2022 (dollars in millions and therms in thousands):



(1) This balance includes interruptible and industrial revenues, which are considered part of retail natural gas revenues.

Total natural gas operating revenues in the graph above include intracompany sales of $12.3 million and $21.2 million for the six months ended June 30, 2023 and 2022, respectively.



The following table presents the current year deferrals and the amortization of prior year decoupling balances reflected in utility natural gas operating revenues for the six months ended June 30 (dollars in thousands):

	Natural Gas Decoupling Revenues	
	2023	2022
Current year decoupling deferrals (a)	$ (10,501)	$ (7,905)
Amortization of prior year decoupling deferrals (b)	(5,457)	(684)
Total natural gas decoupling revenue	$ (15,958)	$ (8,589)

(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 increased $10.5 million for the first half of 2023 as compared to the first half of 2022. The primary changes that occurred during the period were as follows:

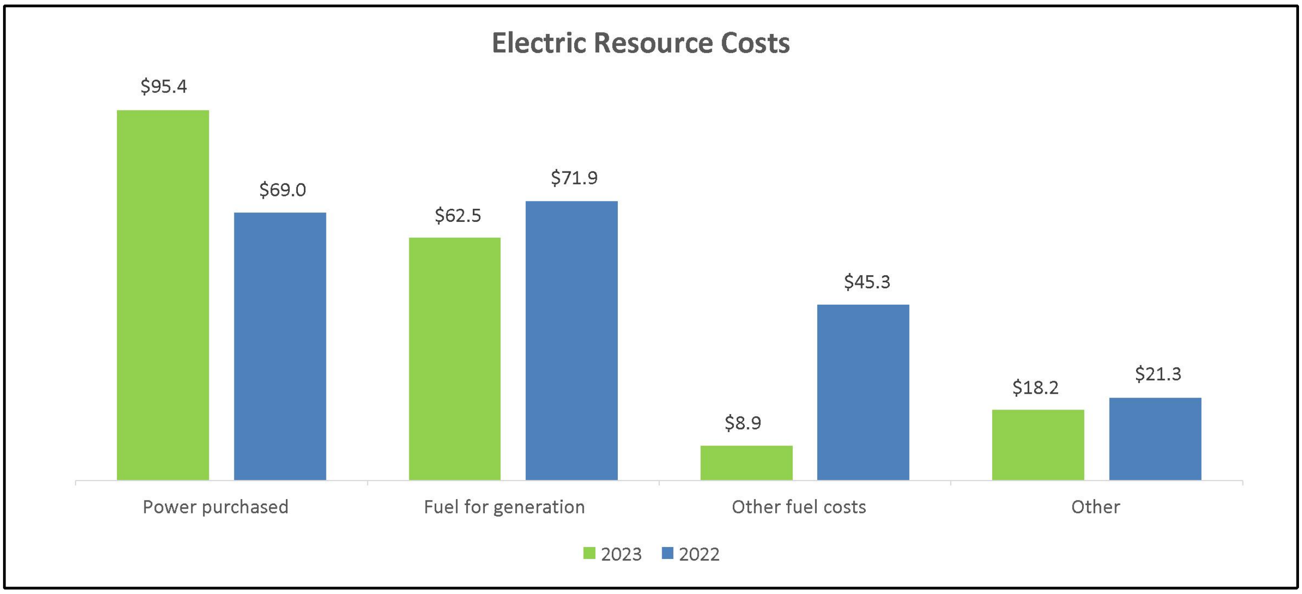
- a $64.9 million increase in natural gas retail revenues (including industrial, which is included in other) due to higher retail rates (increased revenues $68.3 million), partially offset by lower sales volumes (decreased revenues $3.4 million).
  - o Retail rates increased mainly due to PGA rate increases in all jurisdictions (which do not impact utility margin).
  - o Retail natural gas sales volumes decreased primarily due to decreased residential and commercial usage, due to warmer weather (decreasing heating load). Compared to the first half of 2022, residential use per customer decreased 5 percent, and commercial use per customer decreased 2 percent. Heating degree days in Spokane were 11 percent below the prior year and 6 percent below our historical norm. Heating degree days in Medford were consistent with the prior year and 8 percent above normal.
- a $46.8 million decrease in wholesale natural gas revenues due to a decrease in prices (decreased revenues $43.8 million), and a decrease in sales volumes (decreased revenues $3.0 million). The decrease in prices includes the impact of financial losses associated with our hedging activities, which nets with our wholesale revenues. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.
- a $7.4 million decrease in natural gas decoupling revenue primarily due to higher rebates to residential customers in the first quarter of 2023 due to higher than normal usage, as well as higher amortization of surcharge balances.

The following table presents Avista Utilities' average number of electric and natural gas retail customers for the six months ended June 30, 2023 and 2022:

	Electric Customers		Natural Gas Customers	
	2023	2022	2023	2022
Residential	365,040	360,483	340,073	336,261
Commercial	45,224	44,497	37,101	36,748
Interruptible	—	—	50	44
Industrial	1,189	1,197	186	189
Public street and highway lighting	688	676	—	—
Total retail customers	412,141	406,853	377,410	373,242

Utility Resource Costs

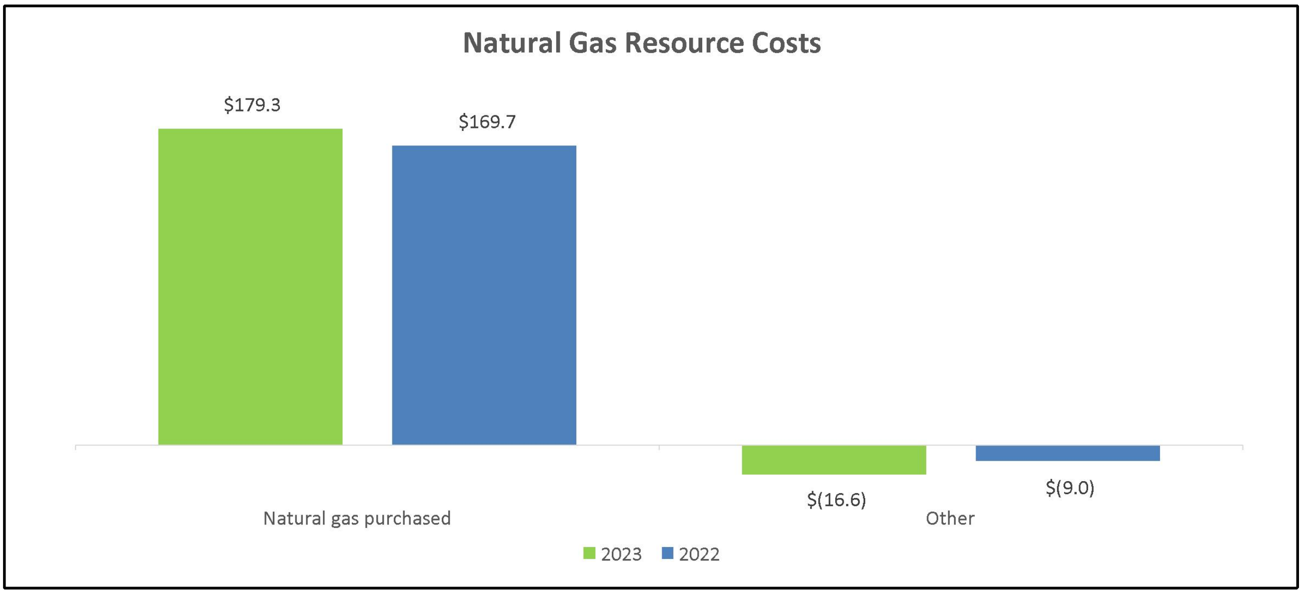
The following graphs present Avista Utilities' resource costs for the six months ended June 30, 2023 and 2022 (dollars in millions):



Total electric resource costs in the graph above include intracompany resource costs of $12.3 million and $21.2 million for the six months ended June 30, 2023 and 2022, respectively.

Total electric resource costs decreased $22.5 million for the first half of 2023 as compared to the first half of 2022. The primary changes that occurred during the period were as follows:

- a $26.4 million increase in power purchased due to an increase in wholesale prices (increased costs $19.5 million), and an increase in the volume of power purchases (increased costs $6.9 million). The change in volumes was primarily the result of fluctuations in customer loads and decreased hydroelectric generation.
- a $9.4 million decrease in fuel for generation primarily due to financial gains associated with our hedging activities, which net with our physical purchases, as well as decreased natural gas prices. This was partially offset by an increase in thermal generation volumes due in part to decreased hydroelectric generation.
- a $36.4 million decrease in other fuel costs, resulting from financial gains associated with our hedging activities. These costs represent fuel and the related derivative instruments purchased for generation but were later sold when conditions indicated it was more economical to sell the fuel as part of the resource optimization process. When the fuel is sold either physically or through a derivative instrument, that revenue is included in sales of fuel.
- a $3.1 million decrease in other electric resource costs, primarily related to an increase in deferred costs associated with net power supply costs above authorized levels during the first quarter of 2023.



Total natural gas resource costs in the graph above include intracompany resource costs of $3.3 million and $4.4 million for the six months ended June 30, 2023 and 2022, respectively.

Total natural gas resource costs increased $2.0 million for the first half of 2023 as compared to the first half of 2022 primarily due to the following:

- a $9.6 million increase in natural gas purchased due to an increase in the price of natural gas (increased costs $22.9 million), partially offset by a decrease in volumes (decreased costs $13.3 million).
- a $7.6 million decrease from net amortizations and deferrals of natural gas costs. In the first quarter of 2023, we had significant deferred natural gas costs in excess of authorized levels due to the high price of natural gas.

Utility Margin

The following table reconciles Avista Utilities' operating revenues, as presented in "Note 17 of the Notes to Condensed Consolidated Financial Statements" to the Non-GAAP financial measure utility margin for the six months ended June 30, 2023 and 2022 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2023	2022	2023	2022	2023	2022	2023	2022
Operating revenues	$ 540,427	$ 549,558	$ 303,919	$ 293,431	$ (15,600)	$ (25,602)	$ 828,746	$ 817,387
Resource costs	185,035	207,519	162,719	160,728	(15,600)	(25,602)	332,154	342,645
Utility margin	$ 355,392	$ 342,039	$ 141,200	$ 132,703	$ —	$ —	$ 496,592	$ 474,742

Electric utility margin increased $13.4 million and natural gas utility margin increased $8.5 million.

Electric utility margin increased primarily due to customer growth and the effects of general rate cases, partially offset by the impacts of the ERM in Washington.

In the first half of 2023, we had a $6.5 million pre-tax expense under the ERM in Washington, compared to a $2.8 million pre-tax expense for the first half of 2022.

Natural gas utility margin increased primarily due to customer growth and the effects of general rate cases.

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 condensed 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

Net income for AEL&P was $1.4 million for the three months ended June 30, 2023 and $0.8 million for the three months ended June 30, 2022. Net income was $5.4 million for the six months ended June 30, 2023, compared to $4.1 million for the six months ended June 30, 2022.

The following table presents AEL&P's operating revenues, resource costs and resulting utility margin for the three and six months ended June 30, 2023 and 2022 (dollars in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2023	2022	2023	2022
Operating revenues	$ 11,194	$ 9,906	$ 25,557	$ 22,960
Resource costs	1,227	1,176	2,018	1,620
Utility margin	$ 9,967	$ 8,730	$ 23,539	$ 21,340

Utility margin for the for the three and six months ended June 30 increased slightly from 2022, primarily due to increased operating revenues resulting from both usage and rate increases compared to the prior year.

Results of Operations - Other Businesses

Our other businesses had a net loss of $2.7 million for the three months ended June 30, 2023 compared to net income of $6.7 million for the three months ended June 30, 2022. Net loss was $3.5 million for the six months ended June 30, 2023, compared to net income of $7.7 million for the six months ended June 30, 2022.

The decrease in net income primarily relates to decreases in the fair value of our investments in 2023, compared to net investment gains recognized in 2022. See "Note 12 of the Notes to the Condensed Consolidated Financial Statements" for further discussion of our equity investment fair value.

Critical Accounting Policies and Estimates

The preparation of our condensed consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect amounts reported in the condensed consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our condensed consolidated financial statements and thus, actual results could differ from the amounts reported and disclosed herein. Our critical accounting policies that require the use of estimates and assumptions were discussed in detail in the 2022 Form 10-K and have not changed materially.

Liquidity and Capital Resources

Overall Liquidity

Our sources of overall liquidity and the requirements for liquidity have not materially changed in the six months ended June 30, 2023. See the 2022 Form 10-K for further discussion.

In March 2023, we issued $250.0 million of first mortgage bonds. A portion of the proceeds from the sale of these bonds will be used for the construction or improvement of utility facilities, and a portion was used to refinance existing indebtedness, including the repayment of our $150.0 million term loan.

As of June 30, 2023, we had $292.4 million of available liquidity under the Avista Corp. committed line of credit, $34.0 million of available liquidity under our letter of credit facility, and $25.0 million under the AEL&P committed line of credit. With our existing credit facilities and the expected issuances of common stock and debt within the next year, we believe we have adequate liquidity to meet our needs for the next 12 months.

Review of Consolidated Cash Flow Statement

Operating Activities

Net cash provided by operating activities was $269.6 million for the six months ended June 30, 2023, compared to $205.9 million for the six months ended June 30, 2022. The increase is primarily due to a decrease in collateral for our derivatives resulting in a $98.5 million increase to operating cash flows in 2023 compared to 2022, a decrease in our accounts and notes receivable balance outstanding resulting in a $78.2 million increase to operating cash flows in 2023 compared to 2022, and a net $7.5 million received for interest rate swap settlements during the period compared to $17.0 million paid in 2022. These increases in operating cash flows were partially offset by decreases in our accounts payable and other current liabilities outstanding balances, which decreased operating cash flows by $130.0 million compared to 2022.

Investing Activities

Net cash used in investing activities was $234.1 million for the six months ended June 30, 2023, compared to $219.4 million for the six months ended June 30, 2022. During the six months ended June 30, 2023, we paid $226.7 million for utility capital expenditures compared to $210.6 million for the six months ended June 30, 2022. Additionally, we contributed capital of $6.5 million to our equity and property investments, compared to $7.8 million in the first half of 2022.

Financing Activities

Net cash used in financing activities was $33.2 million for the six months ended June 30, 2023, compared to net cash provided by financing activities of $12.9 million for the six months ended June 30, 2022. In the six months ended June 30, 2023, we issued $250.0 million of long-term debt, and repaid $6.5 million of maturing long-term debt. This compared to $400.0 million of long-term debt issued in the first half of 2022, of which we used a portion to repay $250.0 million of maturing long-term debt. We also decreased our short-term borrowings by $260.0 million in the first half of 2023, compared to $126.0 million in 2022. In addition, we issued $59.5 million of common stock in 2023, compared to $60.8 million in 2022.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings consisted of the following as of June 30, 2023 and December 31, 2022 (dollars in thousands):

	June 30, 2023		December 31, 2022	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt and leases	$ 14,793	0.3 %	$ 21,084	0.4 %
Short-term borrowings	203,000	3.8 %	463,000	8.8 %
Long-term debt to affiliated trusts	51,547	1.0 %	51,547	1.0 %
Long-term debt and leases	2,637,333	49.7 %	2,387,792	45.4 %
Total debt	2,906,673	54.8 %	2,923,423	55.6 %
Total shareholders’ equity	2,400,421	45.2 %	2,334,668	44.4 %
Total	$ 5,307,094	100.0 %	$ 5,258,091	100.0 %

Our shareholders’ equity increased $65.8 million during the first half of 2023 primarily due to net income and the issuance of common stock, which was 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 flow 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 with various financial institutions in the total amount of $500 million and an expiration date of June 2028, with the option to extend for an additional one year period (subject to customary conditions).

In December 2022, we entered into a revolving credit agreement in the amount of $100 million, which was terminated in June 2023.

In December 2022, we entered into a term loan, in the amount of $150 million with a maturity date of March 30, 2023. In March 2023, we repaid the $150 million outstanding balance on the term loan.

In December 2022, we entered into a continuing letter of credit agreement in the aggregate amount of $50 million. Either party may terminate the agreement at any time.

The following table summarizes the balances outstanding and available liquidity as of June 30, 2023 (dollars in thousands):

	Amount of Facility	Borrowings Outstanding	Letters of Credit Outstanding (1)	Available Liquidity
Line of Credit expiring June 2028	$ 500,000	$ 203,000	$ 4,638	$ 292,362
Letter of Credit Facility	50,000	N/A	16,000	34,000
Total	$ 550,000	$ 203,000	$ 20,638	$ 326,362

(1) Letters of credit are not reflected on the Condensed 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 covenant 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 the case of the letter of credit agreement, other obligations. The committed line of credit agreement 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 June 30, 2023, we were in compliance with this covenant with a ratio of 54.8 percent.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under Avista Corp.'s lines of credit were as follows as of and for the six months ended June 30 (dollars in thousands):

	2023	2022
$500 million line of credit, expiring June 2028		
Maximum balance outstanding during the period	$ 334,500	$ 292,000
Average balance outstanding during the period	259,202	156,718
Average interest rate during the period	5.73 %	1.34 %
Average interest rate at end of the period	6.24 %	2.35 %
$100 million line of credit, terminated June 2023		
Maximum balance outstanding during the period (1)	$ 15,000	N/A
Average balance outstanding during the period (1)	283	N/A
Average interest rate during the period (1)	7.75 %	N/A

(1) Amounts for the period are through the termination date of June 8, 2023.

AEL&P

AEL&P has a $25.0 million committed line of credit that expires in June 2028. As of June 30, 2023, there were no borrowings or letters of credit outstanding under this committed 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 June 30, 2023, AEL&P was in compliance with this covenant with a ratio of 49.4 percent.

As of June 30, 2023, Avista Corp. and its subsidiaries were in compliance with all of 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.

See "Note 9 of the Notes to Condensed Consolidated Financial Statements" for additional information regarding our short-term borrowing arrangements.

Liquidity Expectations

During March 2023, we issued $250 million of long-term debt. We do not expect to issue any additional long-term debt in 2023. We expect to issue $120 million of common stock (including $59.5 million of common stock issued during the six months ended June 30, 2023). The long-term debt and equity issuances in 2023 was used to decrease existing indebtedness, including the repayment of our $150 million term loan in March 2023, and will be used for the construction or improvement of utility facilities throughout the year.

Capital Expenditures

We are making capital investments to enhance service and system reliability for our customers and replace aging infrastructure. Our capital expenditure plans remain materially consistent with those disclosed in our 2022 Form 10-K. See the 2022 Form 10-K for further information on our expected capital expenditures.

Pension Plan

Avista Utilities

In the six months ended June 30, 2023 we contributed $6.7 million to the pension plan. We expect to contribute a total of $50.0 million to the pension plan in the period 2023 through 2027, with an annual contribution of $10.0 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 7 of the Notes to Condensed Consolidated Financial Statements" for additional information regarding the pension plan.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed during the six months ended June 30, 2023 except as follows:

Washington Climate Commitment Act (CCA)

The CCA establishes a cap and trade program to reduce greenhouse gas emissions and achieve the greenhouse gas 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. We purchase allowances recorded as inventory, and record emissions obligations and emissions expense associated with sales. As allowances are used and retired, we remove both the inventory and emissions obligation from the balance sheet. 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 delivered in Washington but is allocated to Idaho customers (wholesale sales) or power generated in Washington that is ultimately delivered to Idaho customers. In May 2023, a model was approved for use in calculating the allowances needed for compliance that assumes hydroelectric generation is first used for wholesale sales, therefore reducing allowances required. As a result, the Act is expected to have minimal financial impact on our electric operations in its initial years. For our Washington natural gas operations, we expect there are additional financial burdens associated with compliance which will be deferred in accordance with our regulatory accounting order in Washington. We are seeking regulatory approval to defer incremental costs related to our Washington and Idaho electric operations.

Washington State Building Codes

In April 2022, the Washington State Building Code Council (SBCC) approved a revised energy code that requires most new commercial buildings and large multifamily buildings to install all-electric space heating. However, an amendment to the code allows for natural gas to supplement electric heat pumps. Additionally, in November 2022, SBCC approved new building and energy codes for residential housing, requiring new residential buildings in Washington to use electricity as the primary heating source. The State Legislature had the opportunity to reject or alter these new codes during their 2023 Regular Session. There was no action by the

Legislature through the regular session that ended in April 2023, and as such the new codes would have absent further action by the SBCC, gone into effect on July 1, 2023.

In March 2023, 23 petitioners filed suit in Washington State Superior Court challenging the validity of the building and energy code changes. The proceeding remains pending.

On April 17, 2023, the Ninth Circuit issued an opinion in a lawsuit between the California Restaurant Association and the City of Berkeley concerning regulation by the City prohibiting the installation of natural gas piping within newly constructed buildings. In its decision, the Court ruled, among other things, the City's ordinance was expressly preempted by the federal Energy Policy and Conservation Act (EPCA), which it held encompasses and preempts building codes that purport to regulate natural gas use by covered products. The City of Berkeley has since filed a petition for en banc review of the Court's decision, which remains pending.

On May 22, 2023, the Company, along with 12 other parties, filed suit in the Federal District Court for the Eastern District of Washington, challenging the SBCC's amendments to the Washington commercial and residential building codes on the grounds that they are also preempted by EPCA. On May 24, 2023, the SBCC voted to delay the effective date of the code amendments at issue by 120 days and commenced an emergency rulemaking process to evaluate additional amendments to the codes in light of the Ninth Circuit's decision in the Berkeley case. On July 18, 2023, the Court declined to issue a preliminary injunction in the case on the grounds that the rules had been suspended and the SBCC was evaluating potential amendments to the same.

The Company continues to engage in both the rulemaking and the legal process.

See the 2022 Form 10-K for further discussion of our environmental issues and contingencies.

Enterprise Risk Management

The material risks to our businesses, and our mitigation process and procedures to address these risks, were discussed in our 2022 Form 10-K and have not materially changed during the six months ended June 30, 2023. See the 2022 Form 10-K.

Financial Risk

Our financial risks have not materially changed during the six months ended June 30, 2023. Refer to the 2022 Form 10-K. The financial risks included below are required interim disclosures, even if they have not materially changed from December 31, 2022.

Interest Rate Risk

We use a variety of techniques to manage our interest rate risks. We have an interest rate risk policy and a policy to limit our variable rate exposures to a percentage of total capitalization. Additionally, interest rate risk is managed by 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. See "Note 6 of the Notes to Condensed Consolidated Financial Statements" for a summary of our interest rate swap derivatives outstanding as of June 30, 2023 and December 31, 2022 and the amount of additional collateral we would have to post in certain circumstances.

Credit Risk

Under the terms of interest rate swap derivatives, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. A downgrade in our credit ratings could further impact the amount of collateral required. See “Credit Ratings” in the 2022 Form 10-K for further information. As of June 30, 2023, we had interest rate swap derivatives outstanding with a notional amount totaling $20.0 million and we had no cash deposited as collateral and no letters of credit outstanding for these interest rate swap derivatives. If our credit ratings were lowered to below “investment grade” based on our interest rate swap derivatives outstanding at June 30, 2023, we would not be required to post additional collateral because all of our outstanding interest rate swaps were in an asset position at the time.

As of June 30, 2023, we had cash deposited as collateral of $55.0 million and letters of credit of $16.0 million outstanding related to our energy contracts. Price movements and/or a downgrade in our credit ratings could impact further the amount of collateral required. See “Credit Ratings” in the 2022 Form 10-K 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 our positions outstanding at June 30, 2023 (including contracts considered derivatives and those considered non-derivatives), we would potentially be required to post the following additional collateral (in thousands):

	June 30, 2023
Additional collateral taking into account contractual thresholds	$ 6,839
Additional collateral without contractual thresholds	10,846

Energy Commodity Risk

Our energy commodity risks have not materially changed during the six months ended June 30, 2023. See the 2022 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of June 30, 2023 expected to settle in each respective year (dollars in thousands). There are no expected deliveries of energy commodity derivatives after 2026.

	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)
Remainder 2023	$ 532	$ 345	$ (152)	$ (11,715)	$ (1,346)	$ (2,840)	$ (2,456)	$ (8,132)
2024	—	—	(587)	(11,948)	136	(898)	(6,479)	(7,338)
2025	—	—	(998)	(1,988)	—	269	(2,834)	(886)
2026	—	—	(206)	(47)	—	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2022 expected to be delivered in each respective year (dollars in thousands). There were no expected deliveries of energy commodity derivatives after 2025.

	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)
2023	$ 1,120	$ —	$ (33,150)	$ 62,753	$ (2,374)	$ (20,018)	$ 17,166	$ (137,585)
2024	—	—	162	(3,879)	—	—	(4,968)	(5,790)
2025	—	—	135	(220)	—	—	(2,924)	(701)

(1) Physical transactions represent commodity transactions where we will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swap derivatives, options, or forward 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 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.

Future Resource Needs

2023 Natural Gas Integrated Resource Plan

In March 2023, we filed our 2023 Natural Gas Integrated Resource Plan (IRP) with the WUTC, IPUC and OPUC. The state commissions review the IRPs and give the public the opportunity to comment. The state commissions do not approve or disapprove of the content in the IRPs; rather they acknowledge the IRPs are prepared in accordance with applicable standards.

Highlights of the 2023 Natural Gas IRP include the following:

- We anticipate having sufficient natural gas resources to meet expected loads, including in Idaho where customer growth is highest, with our current transportation contracts for natural gas.

- Customer forecasts are increasingly difficult to model due to a variety of recently passed rules and codes, including building code updates in Washington.
- Emissions compliance with the CCA in Washington and Climate Protection Plan in Oregon greatly impact our resource strategy, including the use of renewable natural gas, synthetic methane, and credits or allowances.
- Our Idaho preferred resource strategy continues to utilize a least cost basis.

We will monitor these assumptions on an on-going basis and adjust our resource requirements accordingly.

We are required to file a natural gas IRP every two years and we anticipate our next IRP to be filed in 2025.

2023 Electric Integrated Resource Plan

In June 2023, we filed our 2023 Electric IRP with the WUTC and IPUC. The state commissions review the IRPs and give the public the opportunity to comment. The state commissions do not approve or disapprove of the content in the IRPs; rather they acknowledge the IRPs are prepared in accordance with applicable standards.

Highlights of the 2023 Electric IRP include the following:

- The forecast for growth in energy requirements is 0.9 percent per year, higher than the 0.2 percent annual growth rate in the 2021 IRP. Higher growth largely reflects higher residential and commercial electric vehicle forecasts and new building electrification.
- We announced several resource acquisitions and an expected divestiture (Colstrip at the end of 2025) since our 2021 IRP.
- The resource strategy selected in the IRP is designed to achieve an 80 percent reduction in greenhouse gas emissions by 2045.
- We need long-duration storage to serve customers in peak hours after 2035.
- We created a Named Community Investment Fund to increase energy-related investments in disadvantaged communities. The fund will increase distributed energy resources such as energy efficiency, small-scale renewables, and energy storage.

We will monitor these assumptions on an on-going basis and adjust our resource requirements accordingly.

We are required to file an electric IRP every two years and we anticipate our next IRP to be filed in 2025.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The information required by this item is set forth in the Enterprise Risk Management section of "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" and is incorporated herein by reference.

Item 4. 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 June 30, 2023.

There have been no changes in the Company's internal control over financial reporting that occurred during the second quarter of 2023 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. Other Information

Item 1. Legal Proceedings

See “Note 16 of Notes to Condensed Consolidated Financial Statements” in “Part I. Financial Information Item 1. Condensed Consolidated Financial Statements.”

Item 1A. Risk Factors

Refer to the 2022 Form 10-K for disclosure of risk factors that could have a significant impact on our results of operations, financial condition or cash flows and could cause actual results or outcomes to differ materially from those discussed in our reports filed with the SEC (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not materially changed from the disclosures provided in the 2022 Form 10-K with the exception of the following:

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 potential generative artificial intelligence) that is heavily relied upon by us or our counterparties 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 failures could result in significant adverse effects on our operations, results of operations, financial condition and cash flows.

Item 5. Other Information

During the fiscal quarter ended June 30, 2023, 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.

Item 6. Exhibits

15	Letter Re: Unaudited Interim Financial Information (1)
31.1	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) (1)
31.2	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) (1)
32	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) (2)
101.INS	Inline XBRL Instance Document. The instance document does not appear in the interactive data file because its inline XBRL tags are embedded within the inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
104	Cover page formatted as Inline XBRL and contained in Exhibit 101.

(1) Filed herewith.
(2) Furnished herewith.

SIGNATURE

Pursuant to the requirements 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
(Registrant)

Date: August 1, 2023

/s/ Kevin J. Christie
Kevin J. Christie
Senior Vice President, Chief Financial Officer,
Treasurer and Regulatory Affairs Officer
(Principal Financial Officer)

Exhibit 15

August 1, 2023

To the Board of Directors and Shareholders of Avista Corporation
1411 East Mission Ave
Spokane, Washington 99202

We are aware that our report dated August 1, 2023, on our review of interim financial information of Avista Corporation and subsidiaries appearing in this Quarterly report on Form 10-Q for the quarter ended June 30, 2023, is incorporated by reference in Registration Statement Nos. 333-33790, 333-179042 and 333-208986 on Form S-8 and in Registration Statement No. 333-264790 on Form S-3.

/s/ Deloitte & Touche LLP

Portland, Oregon

Exhibit 31.1

CERTIFICATION

I, Dennis P. Vermillion, certify that:

1. I have reviewed this report on Form 10-Q 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: August 1, 2023

/s/ Dennis P. Vermillion

Dennis P. Vermillion

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-Q 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: August 1, 2023

/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, Dennis P. Vermillion, President and Chief Executive Officer of Avista Corporation (the “Company”), and Kevin J. Christie, Senior Vice President, Chief Financial Officer, Treasurer and Regulatory Affairs 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 Quarterly Report on Form 10-Q for the quarter ended June 30, 2023 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: August 1, 2023

/s/ Dennis P. Vermillion

Dennis P. Vermillion
President and Chief Executive Officer

/s/ Kevin J. Christie

Kevin J. Christie
Senior Vice President, Chief Financial Officer,
Treasurer and Regulatory Affairs Officer