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 March 31, 2014 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)	**(Zip Code)**

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

None

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

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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, accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

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 April 30, 2014, 60,169,046 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

AVISTA CORPORATION
INDEX

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 that are 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:

- weather conditions (temperatures, precipitation levels and wind patterns) which affect both energy demand and electric generating capability, including the effect of precipitation and temperature on hydroelectric resources, the effect of wind patterns on wind-generated power, weather-sensitive customer demand, and similar effects on supply and demand in the wholesale energy markets;
- state and federal regulatory 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 and operating costs and discretion over allowed return on investment;
- changes in wholesale energy prices that can affect operating income, cash requirements to purchase electricity and natural gas, value received for wholesale sales, collateral required of us by counterparties on wholesale energy transactions and credit risk to us from such transactions, and the market value of derivative assets and liabilities;
- economic conditions in our service areas, including the economy's effects on customer demand for utility services;
- declining energy demand related to customer energy efficiency and/or conservation measures;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions and the global economy;
- the potential effects of legislation or administrative rulemaking, including possible effects on our generating resources of restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;
- political pressures or regulatory practices that could constrain or place additional cost burdens on our energy supply sources, such as campaigns to halt coal-fired power generation and opposition to other thermal generation, wind turbines or hydroelectric facilities;
- changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension and other postretirement benefit plans, which can affect future funding obligations, pension and other postretirement benefit expense and the related liabilities;
- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, and prices of purchased energy and demand for energy sales including related energy commodity derivative instruments that we rely upon to hedge our wholesale energy risks;

- the outcome of pending regulatory and legal proceedings arising out of the "western energy crisis" of 2000 and 2001, including possible refunds;
- the outcome of legal proceedings and other contingencies;
- changes in environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs and our compliance with these matters;
- wholesale and retail competition including alternative energy sources, growth in customer-owned power resource technologies that displace utility-supplied energy or that may be sold back to the utility, and alternative energy suppliers and delivery arrangements;
- growth or decay of our customer base and the extent to which new uses for our services may materialize or existing uses may decline;
- the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;
- severe weather or natural disasters that can disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies and support services;
- explosions, fires, accidents, mechanical breakdowns, or other incidents that may impair assets and may disrupt operations of any of our generation facilities, transmission and distribution systems or other operations;
- public injuries or damage arising from or allegedly arising from our operations;
- blackouts or disruptions of interconnected transmission systems (the regional power grid);
- disruption to information systems, automated controls and other technologies that we rely on for our operations, communications and customer service;
- terrorist attacks, cyber attacks or other malicious acts that may disrupt or cause damage to our utility assets or to the national economy in general, including any effects of terrorism, cyber attacks or vandalism that damage or disrupt information technology systems;
- cyber attacks or other potential lapses that result in unauthorized disclosure of private information, which could result in liabilities against us, costs to investigate, remediate and defend, and damage to our reputation;
- delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;
- changes in the costs to implement new information technology systems and/or obstacles that impede our ability to complete such projects timely and effectively;
- changes in the long-term global and Pacific Northwest climates, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;
- changes in industrial, commercial and residential growth and demographic patterns in our service territory or changes in demand by significant customers;
- the loss of key suppliers for materials or services or disruptions to the supply chain;
- default or nonperformance on the part of any parties from which we purchase and/or sell capacity or energy;
- deterioration in the creditworthiness of our customers;
- potential decline in our credit ratings, with effects including impeded access to capital markets, higher interest costs, and restrictive covenants in our financing arrangements and wholesale energy contracts;
- increasing health care costs and the resulting effect on employee injury costs and health insurance provided to our employees and retirees;
- increasing costs of insurance, more restrictive coverage terms and our ability to obtain insurance;
- 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;
- the potential effects of negative publicity regarding business practices, whether true or not, which could result in litigation or a decline in our common stock price;
- changes in technologies, possibly making some of the current technology obsolete;

- changes in tax rates and/or policies;
- 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 that we recover interest costs through utility operations;
- changes in the payment acceptance policies of Ecova’s client vendors that could reduce operating revenues;
- potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities; and
- changes in our strategic business plans, which may 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.

Our expectations, beliefs and projections are expressed in good faith. We believe they are reasonable based on, without limitation, an examination of historical operating trends, our records and other information available from third parties. However, there can be no assurance that our expectations, beliefs or projections will be achieved 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 that any such factor or combination of factors may cause actual results to differ materially from those contained in any forward-looking statement.

Available Information

Our Web site address is www.avistacorp.com. We make annual, quarterly and current reports available at our Web site as soon as practicable after electronically filing these reports with the Securities and Exchange Commission. Information contained on our Web site is not part of this report.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands, except per share amounts
(Unaudited)

	2014	2013
Operating Revenues:		
Utility revenues	$ 437,124	$ 431,127
Ecova revenues	44,384	42,407
Other non-utility revenues	9,454	9,372
Total operating revenues	490,962	482,906
Operating Expenses:		
Utility operating expenses:		
Resource costs	220,497	229,630
Other operating expenses	67,337	65,444
Depreciation and amortization	30,726	27,935
Taxes other than income taxes	28,146	25,817
Ecova operating expenses:		
Other operating expenses	37,877	35,990
Depreciation and amortization	3,709	3,493
Other non-utility operating expenses:		
Other operating expenses	9,383	9,345
Depreciation and amortization	147	190
Total operating expenses	397,822	397,844
Income from operations	93,140	85,062
Interest expense	19,084	19,692
Interest expense to affiliated trusts	111	118
Capitalized interest	(661)	(940)
Other income-net	(2,551)	(2,145)
Income before income taxes	77,157	68,337
Income tax expense	28,176	25,236
Net income	48,981	43,101
Net income attributable to noncontrolling interests	(482)	(760)
Net income attributable to Avista Corporation shareholders	$ 48,499	$ 42,341
Weighted-average common shares outstanding (thousands), basic	60,122	59,866
Weighted-average common shares outstanding (thousands), diluted	60,168	59,898
Earnings per common share attributable to Avista Corporation shareholders:		
Basic	$ 0.81	$ 0.71
Diluted	$ 0.81	$ 0.71
Dividends declared per common share	$ 0.3175	$ 0.305

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands
(Unaudited)

	2014	2013
Net income	$ 48,981	$ 43,101
Other Comprehensive Income (Loss):		
Unrealized investment gains/(losses) - net of taxes of $463 and $(39), respectively	785	(70)
Reclassification adjustment for realized gains on investment securities included in net income - net of taxes of $(1) and $(1), respectively	(2)	(1)
Change in unfunded benefit obligation for pension and other postretirement benefit plans - net of taxes of $59 and $99, respectively	111	184
Total other comprehensive income	894	113
Comprehensive income	49,875	43,214
Comprehensive income attributable to noncontrolling interests	(482)	(760)
Comprehensive income attributable to Avista Corporation shareholders	$ 49,393	$ 42,454

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS

Avista Corporation

Dollars in thousands
(Unaudited)

		March 31, 2014		December 31, 2013
Assets:				
Current Assets:				
Cash and cash equivalents	$	90,172	$	82,574
Accounts and notes receivable-less allowances of $44,598 and $44,309, respectively		202,820		221,343
Utility energy commodity derivative assets		13,925		3,022
Regulatory asset for utility derivatives		—		10,829
Investments and funds held for clients		95,851		96,688
Materials and supplies, fuel stock and natural gas stored		32,804		44,946
Deferred income taxes		24,288		24,788
Income taxes receivable		—		7,783
Other current assets		44,526		57,706
Total current assets		504,386		549,679
Net Utility Property:				
Utility plant in service		4,341,383		4,290,464
Construction work in progress		157,330		160,323
Total		4,498,713		4,450,787
Less: Accumulated depreciation and amortization		1,271,082		1,248,362
Total net utility property		3,227,631		3,202,425
Other Non-current Assets:				
Investment in exchange power-net		13,271		13,883
Investment in affiliated trusts		11,547		11,547
Goodwill		76,257		76,257
Intangible assets-net of accumulated amortization of $39,410 and $36,634, respectively		38,610		39,576
Long-term energy contract receivable of Spokane Energy		37,612		40,619
Other property and investments-net		48,171		58,555
Total other non-current assets		225,468		240,437
Deferred Charges:				
Regulatory assets for deferred income tax		69,084		71,421
Regulatory assets for pensions and other postretirement benefits		155,205		156,984
Other regulatory assets		105,807		102,915
Non-current utility energy commodity derivative assets		3,545		854
Non-current regulatory asset for utility derivatives		11,654		23,258
Other deferred charges		13,298		13,950
Total deferred charges		358,593		369,382
Total assets	$	4,316,078	$	4,361,923

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

Dollars in thousands
(Unaudited)

	March 31, 2014	December 31, 2013
Liabilities and Equity:		
Current Liabilities:		
Accounts payable	$ 163,655	$ 182,088
Client fund obligations	97,128	99,117
Current portion of long-term debt	372	358
Current portion of nonrecourse long-term debt of Spokane Energy	13,872	16,407
Short-term borrowings	111,000	171,000
Utility energy commodity derivative liabilities	3,360	10,875
Other current liabilities	180,834	145,495
Total current liabilities	570,221	625,340
Long-term debt	1,272,530	1,272,425
Nonrecourse long-term debt of Spokane Energy	—	1,431
Long-term debt to affiliated trusts	51,547	51,547
Long-term borrowings under committed line of credit	42,000	46,000
Regulatory liability for utility plant retirement costs	245,456	242,850
Pensions and other postretirement benefits	113,416	122,513
Deferred income taxes	534,540	535,343
Other non-current liabilities and deferred credits	119,295	130,318
Total liabilities	2,949,005	3,027,767
Commitments and Contingencies (See Notes to Condensed Consolidated Financial Statements)		
Redeemable Noncontrolling Interests	15,960	15,889
Equity:		
Avista Corporation Shareholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 60,161,140 and 60,076,752 shares outstanding, respectively	899,037	896,993
Accumulated other comprehensive loss	(4,925)	(5,819)
Retained earnings	436,370	407,092
Total Avista Corporation shareholders' equity	1,330,482	1,298,266
Noncontrolling Interests	20,631	20,001
Total equity	1,351,113	1,318,267
Total liabilities and equity	$ 4,316,078	$ 4,361,923

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands
(Unaudited)

	2014	2013
Operating Activities:		
Net income	$ 48,981	$ 43,101
Non-cash items included in net income:		
Depreciation and amortization	34,582	31,618
Provision for deferred income taxes	1,453	1,120
Power and natural gas cost amortizations (deferrals), net	(8,041)	2,545
Amortization of debt expense	953	947
Amortization of investment in exchange power	613	613
Stock-based compensation expense	1,551	1,464
Equity-related AFUDC	(2,034)	(1,391)
Pension and other postretirement benefit expense	7,415	10,949
Amortization of Spokane Energy contract	3,007	2,764
Other	4,212	1,118
Contributions to defined benefit pension plan	(11,000)	(14,670)
Changes in certain current assets and liabilities:		
Accounts and notes receivable	17,257	2,432
Materials and supplies, fuel stock and natural gas stored	12,141	17,137
Other current assets	30,333	(14,288)
Accounts payable	(11,065)	(20,778)
Other current liabilities	26,540	40,698
Net cash provided by operating activities	156,898	105,379
Investing Activities:		
Utility property capital expenditures (excluding equity-related AFUDC)	(59,725)	(70,645)
Other capital expenditures	(3,929)	(819)
Federal grant payments received	876	1,567
Decrease (increase) in funds held for clients	(9,346)	2,816
Purchase of securities available for sale	—	(24,956)
Sale and maturity of securities available for sale	11,403	7,000
Other	24	(1,649)
Net cash used in investing activities	(60,697)	(86,686)

The Accompanying Notes are an Integral Part of These Statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands
(Unaudited)

	2014	2013
Financing Activities:		
Net increase (decrease) in short-term borrowings	$ (60,000)	$ 500
Borrowings from Ecova line of credit	—	3,000
Repayment of borrowings from Ecova line of credit	(4,000)	(3,000)
Redemption and maturity of long-term debt	(69)	(101)
Maturity of nonrecourse long-term debt of Spokane Energy	(3,966)	(3,622)
Issuance of common stock	638	1,149
Cash dividends paid	(19,217)	(18,384)
Increase (decrease) in client fund obligations	(1,989)	15,399
Other	—	99
Net cash used in financing activities	(88,603)	(4,960)
Net increase in cash and cash equivalents	7,598	13,733
Cash and cash equivalents at beginning of period	82,574	75,464
Cash and cash equivalents at end of period	$ 90,172	$ 89,197
Supplemental Cash Flow Information:		
Cash paid (received) during the period:		
Interest	$ 8,107	$ 7,391
Income taxes	(99)	1,329
Non-cash financing and investing activities:		
Accounts payable for capital expenditures	5,168	4,730
Valuation adjustment for redeemable noncontrolling interests	3	2,870

The Accompanying Notes are an Integral Part of These Statements.

Table of Contents

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

Avista Corporation

For the Three Months Ended March 31
Dollars in thousands
(Unaudited)

	2014	2013
Common Stock, Shares:		
Shares outstanding at beginning of period	60,076,752	59,812,796
Issuance of common stock	84,388	99,291
Shares outstanding at end of period	60,161,140	59,912,087
Common Stock, Amount:		
Balance at beginning of period	$ 896,993	$ 889,237
Equity compensation expense	1,619	1,461
Issuance of common stock, net of issuance costs	638	1,149
Equity transactions of consolidated subsidiaries	(213)	(88)
Balance at end of period	899,037	891,759
Accumulated Other Comprehensive Loss:		
Balance at beginning of period	(5,819)	(6,700)
Other comprehensive income	894	113
Balance at end of period	(4,925)	(6,587)
Retained Earnings:		
Balance at beginning of period	407,092	376,940
Net income attributable to Avista Corporation shareholders	48,499	42,341
Cash dividends paid (common stock)	(19,217)	(18,384)
Valuation adjustments and other noncontrolling interests activity	(4)	(2,093)
Balance at end of period	436,370	398,804
Total Avista Corporation shareholders' equity	1,330,482	1,283,976
Noncontrolling Interests:		
Balance at beginning of period	20,001	17,658
Net income attributable to noncontrolling interests	458	733
Other	172	2,371
Balance at end of period	20,631	20,762
Total equity	$ 1,351,113	$ 1,304,738
Redeemable Noncontrolling Interests:		
Balance at beginning of period	$ 15,889	$ 4,938
Net income attributable to noncontrolling interests	24	27
Purchase of subsidiary noncontrolling interests	(3)	—
Valuation adjustments and other noncontrolling interests activity	50	3,005
Balance at end of period	$ 15,960	$ 7,970

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 Corporation (Avista Corp. or the Company) for the interim periods ended March 31, 2014 and 2013 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. The condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. 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, 2013 (2013 Form 10-K). Please refer to the section “Acronyms and Terms” in the 2013 Form 10-K for definitions of terms. The acronyms and terms are an integral part of these condensed consolidated financial statements.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation is an energy company engaged in the generation, transmission and distribution of electricity and distribution of natural gas, as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities provides electric distribution and transmission, as well as 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 generating facilities in Washington, Idaho, Oregon and Montana. The Company also supplies electricity to a small number of customers in Montana, most of whom are employees who operate one of the Montana generating facilities. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, except Spokane Energy, LLC (Spokane Energy). Avista Capital’s subsidiaries include Ecova, Inc. (Ecova), an 80.2 percent owned subsidiary as of March 31, 2014. Ecova is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America. See Note 12 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, including Ecova 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.

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on net income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense and totaled the following amounts for the three months ended March 31 (dollars in thousands):

	2014	2013
Utility taxes	$ 19,738	$ 17,906

Other Income-Net

Other Income-net consisted of the following items for the three months ended March 31 (dollars in thousands):

	2014	2013
Interest income	$ (274)	$ (258)
Interest income on regulatory deferrals	(44)	(13)
Equity-related AFUDC	(2,034)	(1,391)
Net loss on investments	40	398
Other income	(239)	(881)
Total	$ (2,551)	$ (2,145)

Materials and Supplies, Fuel Stock and Natural Gas Stored

Inventories of materials and supplies, fuel stock and natural gas stored are recorded at average cost for our regulated operations and the lower of cost or market for our non-regulated operations and consisted of the following as of March 31, 2014 and December 31, 2013 (dollars in thousands):

	March 31, 2014	December 31, 2013
Materials and supplies	$ 29,158	$ 28,747
Fuel stock	3,639	3,170
Natural gas stored	7	13,029
Total	$ 32,804	$ 44,946

Investments and Funds Held for Clients and Client Fund Obligations

In connection with the bill paying services, Ecova collects funds from its clients and remits the funds to the appropriate utility or other service provider. Some of the funds collected are invested by Ecova and classified as investments and funds held for clients, and a related liability for client fund obligations is recorded. Investments and funds held for clients include cash and cash equivalent investments, money market funds and investment securities classified as available for sale. Ecova does not invest the funds directly for the clients' benefit; therefore, Ecova bears the risk of loss associated with the investments. Investments and funds held for clients as of March 31, 2014 are as follows (dollars in thousands):

	Amortized Cost (1)	Unrealized Gain (Loss)	Fair Value
Cash and cash equivalents	$ 13,618	$ —	$ 13,618
Money market funds	23,034	—	23,034
Securities available for sale:			
U.S. government agency	55,638	(1,311)	54,327
Municipal	3,086	23	3,109
Corporate fixed income – industrial	752	11	763
Certificates of deposit	1,000	—	1,000
Total securities available for sale	60,476	(1,277)	59,199
Total investments and funds held for clients	$ 97,128	$ (1,277)	$ 95,851

Investments and funds held for clients as of December 31, 2013 are as follows (dollars in thousands):

	Amortized Cost (1)	Unrealized Gain (Loss)	Fair Value
Cash and cash equivalents	$ 16,147	$ —	$ 16,147
Money market funds	11,180	—	11,180
Securities available for sale:			
U.S. government agency	63,633	(2,555)	61,078
Municipal	3,497	21	3,518
Corporate fixed income – financial	3,000	—	3,000
Corporate fixed income – industrial	753	12	765
Certificates of deposit	1,000	—	1,000
Total securities available for sale	71,883	(2,522)	69,361
Total investments and funds held for clients	$ 99,210	$ (2,522)	$ 96,688

(1) Amortized cost represents the original purchase price of the investments, plus or minus any amortized purchase premiums or accreted purchase discounts.

Investments and funds held for clients are classified as a current asset since these funds are held for the purpose of satisfying the client fund obligations. As of March 31, 2014 and December 31, 2013, approximately 94 percent and 95 percent of the investment portfolio, respectively, were rated AA-, Aa3 and higher by nationally recognized statistical rating organizations. All fixed income securities were rated as investment grade as of March 31, 2014 and December 31, 2013.

Ecova management reviews its investments continuously for indicators of other-than-temporary impairment. To make this determination, management employs a methodology that considers available quantitative and qualitative evidence in evaluating potential impairment of its investments. If the cost of an investment exceeds its fair value, management evaluates, among other factors, general market conditions, credit quality of instrument issuers, the length of time and extent to which the fair value is less than cost, and whether it has plans to sell the security or it is more-likely-than not that the Company will be required to sell the security before recovery. Management also considers specific adverse conditions related to the financial health of and specific prospects for the issuer as well as other cash flow factors. Once a decline in fair value is determined to be other-than-temporary, an impairment charge is recorded in earnings and a new cost basis in the investment is established. Based on management's analysis, securities available for sale do not meet the criteria for other-than-temporary impairment as of March 31, 2014 or December 31, 2013.

The following is a summary of the disposition of available-for-sale securities for the three months ended March 31 (dollars in thousands):

	2014	2013
Proceeds from sales, maturities and calls	$ 11,403	$ 7,000
Gross realized gains	3	2
Gross realized losses	—	—

Contractual maturities of securities available for sale as of March 31, 2014 and December 31, 2013 are as follows (dollars in thousands):

	Due within 1 year	After 1 but within 5 years	After 5 but within 10 years	After 10 years	Total
March 31, 2014	$ 2,235	$ 10,508	$ 43,460	$ 2,996	$ 59,199
December 31, 2013	5,382	12,745	48,310	2,924	69,361

Actual maturities may differ due to call or prepayment rights and the effective maturity was 2.9 years as of March 31, 2014 and 3.0 years as of December 31, 2013.

Goodwill

Goodwill arising from acquisitions represents the excess of the purchase price over the estimated fair value of net assets acquired. The Company evaluates goodwill for impairment using a combination of the discounted cash flow model and a market approach on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of December 31, 2013 for Ecova and as of November 30, 2013 for the other businesses and determined that goodwill was not impaired at that time.

The carrying amount of goodwill as of March 31, 2014 and December 31, 2013 are as follows (dollars in thousands):

	Ecova	Other	Accumulated Impairment Losses	Total
March 31, 2014	$ 71,011	$ 12,979	$ (7,733)	$ 76,257
December 31, 2013	$ 71,011	$ 12,979	$ (7,733)	$ 76,257

There have been no acquisitions or adjustments to goodwill during the three months ended March 31, 2014. Accumulated impairment losses are attributable to the other businesses.

Intangible Assets

Amortization expense related to Intangible Assets was as follows for the three months ended March 31 (dollars in thousands):

	2014	2013
Intangible asset amortization	$ 2,776	$ 2,579

The following table details the estimated amortization expense related to Intangible Assets for each of the next five years ending December 31 (dollars in thousands):

	Remaining 2014	2015	2016	2017	2018
Estimated amortization expense	$ 7,863	$ 8,818	$ 7,697	$ 6,887	$ 4,100

The gross carrying amount and accumulated amortization of Intangible Assets as of March 31, 2014 and December 31, 2013 are as follows (dollars in thousands):

	Estimated Useful Lives	March 31, 2014	December 31, 2013
Client relationships	2 - 12 years	$ 33,562	$ 33,562
Software development costs	3 - 7 years	41,146	39,327
Other	1 - 10 years	3,312	3,321
Total intangible assets		78,020	76,210
Client relationships accumulated amortization		(13,347)	(12,336)
Software development costs accumulated amortization		(23,437)	(21,861)
Other accumulated amortization		(2,626)	(2,437)
Total accumulated amortization		(39,410)	(36,634)
Total intangible assets - net		$ 38,610	$ 39,576

As of March 31, 2014 and December 31, 2013, all of the intangible assets reported above are associated with Ecova.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Condensed Consolidated Balance Sheets measured at estimated fair value. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for a derivative depends on the intended use of such derivative and the resulting designation.

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Utilities to offset 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. The orders provide for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Condensed Consolidated Statements of Income. Realized gains or losses are recognized in the period of delivery, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. Regulatory assets are assessed regularly and are probable for 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 that are 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 that is determined to be other-than-temporary.

Fair Value Measurements

Fair value represents the price that would be received to sell 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, investments and funds held for clients, deferred compensation assets, as well as derivatives related to interest rate swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Condensed Consolidated Balance Sheets. See Note 9 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

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

- rates for regulated services are established by or subject to approval by independent third-party regulators,

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

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future) are reflected as deferred charges or credits on the Condensed Consolidated Balance Sheets. These costs and/or obligations are not reflected in the Condensed Consolidated Statements of Income until the period during which matching revenues are recognized. If at some point in the future the Company determines that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

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

Redeemable Noncontrolling Interests

Certain option holders of Ecova have the right to put their shares back to Ecova at their discretion during an annual put window. Stock options and other outstanding redeemable stock are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price).

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the following as of March 31, 2014 and December 31, 2013 (dollars in thousands):

	March 31, 2014	December 31, 2013
Unfunded benefit obligation for pensions and other postretirement benefit plans - net of taxes of $(2,220) and $(2,280), respectively	$ (4,122)	$ (4,233)
Unrealized loss on securities available for sale - net of taxes of $(474) and $(936), respectively	(803)	(1,586)
Total accumulated other comprehensive loss	$ (4,925)	$ (5,819)

The following table details the reclassifications out of accumulated other comprehensive loss by component for the three months ended March 31 (dollars in thousands):

Details about Accumulated Other Comprehensive Loss Components	Amounts Reclassified from Accumulated Other Comprehensive Loss 2014	2013	Affected Line Item in Statement of Income
Realized gains on investment securities	$ 3	$ 2	Other income-net
	3	2	Total before tax
	(1)	(1)	Tax expense
	$ 2	$ 1	Net of tax
Amortization of defined benefit pension items			
Amortization of net loss	$ (1,952)	$ (4,891)	(a)
Adjustment due to effects of regulation	1,782	4,608	(a)
	(170)	(283)	Total before tax
	59	99	Tax benefit
	$ (111)	$ (184)	Net of tax

(a) These accumulated other comprehensive loss components are included in the computation of net periodic pension cost (see Note 6 for additional details).

Appropriated Retained Earnings

In accordance with the hydroelectric licensing requirements of section 10(d) of the Federal Power Act (FPA), the Company maintains an appropriated retained earnings account for any earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. The rate of return on investment is specified in the various hydroelectric licensing agreements for the Clark Fork River and Spokane River. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company calculates the earnings in excess of the specified rate of return on an annual basis. The appropriated retained earnings amounts included in retained earnings were as follows as of March 31, 2014 and December 31, 2013 (dollars in thousands):

	March 31, 2014	December 31, 2013
Appropriated retained earnings	$ 9,714	$ 9,714

Dividends

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

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements, and
- the hydroelectric licensing requirements of section 10(d) of the FPA.

Under the covenant applicable to the Company's committed line of credit agreement, which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time, the amount of retained earnings available for dividends at March 31, 2014 was limited to approximately $342.9 million.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses losses that do not meet these conditions for accrual, if there is a reasonable possibility that a loss may be incurred.

NOTE 2. NEW ACCOUNTING STANDARDS

There are no accounting standards that were recently issued that impact the Company during 2014. The Company will continue to evaluate all new accounting standards as they are issued to determine if they impact the Company's financial condition, results of operations and cash flows.

NOTE 3. VARIABLE INTEREST ENTITIES

Lancaster Power Purchase Agreement

The Company has a power purchase agreement (PPA) for the purchase of all the output of the Lancaster Plant, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho, owned by an unrelated third-party (Rathdrum Power LLC), through 2026.

Avista Corp. has a variable interest in the PPA. Accordingly, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Plant and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. Accordingly, neither the Lancaster Plant nor Rathdrum Power LLC is included in Avista Corp.'s condensed consolidated financial statements. The Company has a future contractual obligation of approximately $292 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

Palouse Wind Power Purchase Agreement

In June 2011, the Company entered into a 30-year PPA with Palouse Wind, LLC (Palouse Wind), an affiliate of First Wind Holdings, LLC. The PPA relates to a wind project that was developed by Palouse Wind in Whitman County, Washington and under the terms of the PPA, the Company acquires all of the power and renewable attributes produced by the wind project for a fixed price per MWh, which escalates annually, without consideration for market fluctuations. The wind project has a nameplate capacity of approximately 105 MW and is expected to produce approximately 40 aMW annually. The project was completed and energy deliveries began during the fourth quarter of 2012. Under the PPA, the Company has an annual option to purchase the wind project following the 10^{th} anniversary of the commercial operation date at a fixed price determined under the contract.

The Company evaluated this agreement to determine if it has a variable interest which must be consolidated. Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Palouse Wind facility due to the fact that it pays a fixed price per MWh, which represents the only financial obligation, and does not have any input into the management of the day-to-day operations of the facility. Accordingly, Palouse Wind is not included in Avista Corp.'s condensed consolidated financial statements. The Company has a future contractual obligation of approximately $600 million under the PPA (representing the charges associated with purchasing the energy and renewable attributes through 2042) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

NOTE 4. BUSINESS ACQUISITIONS

Alaska Energy and Resources Company - Avista Corporation

On November 4, 2013, the Company entered into an agreement and plan of merger (Merger Agreement) with Alaska Energy and Resources Company (AERC), a privately-held company based in Juneau, Alaska. If all necessary approvals are received, when the transaction is complete, AERC will become a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is Alaska Electric Light & Power Company (AEL&P), a regulated utility which provides electric services to approximately 16,000 customers in the City and Borough of Juneau, Alaska. In 2013, AEL&P had annual revenues of $42.6 million, a total rate base of $109 million and had 60 full-time employees. The utility has a firm retail peak load of approximately 68 MW. AEL&P owns four hydroelectric generating facilities, having a total present capacity of 24.7 MW, and has a power purchase commitment for the output of the Snettisham hydroelectric project, having a present capacity of 78 MW, for a total hydroelectric capacity of 102.7 MW. AEL&P is not interconnected to any other electric system. The utility also has 93.9 MW of diesel generating capacity to provide back-up service to firm customers when necessary.

In addition to the regulated utility, AERC owns the AJT Mining subsidiary, which is an inactive mining company holding certain properties.

The merger consideration at closing will be $170 million, less AERC's indebtedness and is subject to other customary closing adjustments (Merger Consideration). The transaction will be funded primarily through the issuance of Avista Corp. common stock to the shareholders of AERC. The transaction is expected to close by July 1, 2014, following the receipt of necessary regulatory approvals, the approval of the merger transaction by the requisite number of AERC shareholders and the satisfaction of other closing conditions. Avista Corp. shareholder approval is not required.

Pursuant to the Merger Agreement, among other things, each of the issued and outstanding shares of AERC common stock (other than Dissenting Shares) will be converted into the right to receive consideration as follows:

i. the number of shares of Avista Corp. common stock equal to one share of AERC common stock multiplied by the Exchange Ratio; and

ii. a portion of the Representative Reimbursement Amount.

For purposes of the foregoing:

The ***Exchange Ratio*** is the ratio obtained by dividing the Per Share Amount by (i) $21.48 if the Avista Corp. Closing Price is less than or equal to $21.48, (ii) the Avista Corp. Closing Price, if the Avista Corp. Closing Price is greater than $21.48 and less than $34.30 or (iii) $34.30 if the Avista Corp. Closing Price is greater than or equal to $34.30.

The ***Per Share Amount*** is the amount determined by *dividing* (a) the Merger Consideration (as adjusted) *by* (b) the aggregate number of shares of AERC common stock outstanding immediately prior to the closing of the transaction.

The ***Representative Reimbursement Amount*** is a $500,000 cash payment to be made by Avista Corp. at the Closing to the Shareholders' Representative account. The purpose of the Representative Reimbursement Amount is to reimburse the Shareholders' Representative for expenses incurred by the Shareholders' Representative in acting for the current shareholders of AERC in connection with the Merger. The total Merger Consideration will be reduced by the Representative Reimbursement Amount.

Dissenting Shares will not be converted into, or represent the right to receive, the Merger Consideration or any portion of the Representative Reimbursement Amount. Such shareholders will be entitled to receive payment of the fair value of Dissenting Shares held by them in accordance with the provisions of AS 10.06.580 of the Alaska Corporations Code. Any amounts paid to Dissenting Shares over the amounts otherwise payable in the form of Merger Consideration are indemnified expenses owed by AERC to Avista Corp.

The Merger Agreement has been approved by Avista Corp.'s and AERC's Boards of Directors, the UTC, the IPUC, the Public Utility Commission of Oregon (OPUC), the U.S. Federal Trade Commission and the Antitrust Division of the U.S. Department of Justice, but the consummation of the transaction is subject to the satisfaction or waiver of specified closing conditions, including:

- the registration under the Securities Act of 1933 of the shares of common stock that will be issued to AERC shareholders;
- the approval of such shares for listing on the New York Stock Exchange;
- the approval of the merger transaction by the requisite number of AERC shareholders;
- the receipt of regulatory approvals and other consents required to consummate the merger transaction, including, among others, approvals from the Regulatory Commission of Alaska and any other applicable regulatory bodies on the terms and conditions specified in the definitive purchase agreement;
- the absence of the occurrence of a material adverse effect (as defined in the Merger Agreement) relating to either AERC or Avista Corp. after the date of the signed agreement; and
- other customary closing conditions.

The Merger Agreement also provides for customary termination rights for each of the Company and AERC, including the right for either party to terminate if the Merger has not been consummated by December 31, 2014, provided, however, that the failure of the Merger to have been consummated on or before December 31, 2014 was not caused by the failure of such party or any affiliate of such party to perform any of its obligations under the Merger Agreement. Upon termination of the Merger Agreement in accordance with its terms, there will be no further liability under the agreement except that nothing shall relieve any party thereto from liability for any breach of the agreement.

There may be certain commitments and contingencies that will be assumed when the merger transaction is consummated; however, Avista Corp. has not fully completed its evaluation of all the potential commitments and contingencies as of the date of this filing.

During the three months ended March 31, 2014, Avista Corp. incurred $0.5 million (pre-tax) of transaction related fees which have been expensed and presented in the Condensed Consolidated Statements of Income in other operating expenses within utility operating expenses. Since the start of the planned transaction through March 31, 2014, Avista Corp. has expensed $2.1 million (pre-tax) in total transaction fees associated with the transaction and Avista Corp. expects to incur additional transaction related fees upon consummation of the transaction.

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Utilities 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 Utilities utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these commodity price exposures. The Company has an energy resources risk policy and control procedures to manage these risks. The Company's Risk Management Committee establishes the Company's energy resources risk policy and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other members of management. The Audit Committee of the Company's Board of Directors periodically reviews and discusses enterprise risk management processes, and it focuses on the Company’s material financial and accounting risk exposures and the steps management has undertaken to control them.

As part of the Company's resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve the Company's load obligations and the use of these resources to capture available economic value. The Company transacts in wholesale markets by selling and purchasing 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 the related financial risks. These transactions range from terms of intra-hour up to multiple years.

Avista Utilities makes continuing projections of:

- electric loads at various points in time (ranging from intra-hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data and contract terms, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of streamflows, availability of generating units, historic and forward market information, contract terms, and experience.

On the basis of these projections, the Company makes purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative instruments to match expected resources to expected electric load requirements and reduce exposure to electricity (or fuel) market price changes. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

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

Avista Utilities’ optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative financial instruments.

As part of its resource procurement and management of its natural gas business, Avista Utilities 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 Utilities’ distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Utilities plans and executes a series of transactions to hedge a significant portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Utilities also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Natural gas resource optimization activities include:

- wholesale market sales of surplus natural gas supplies,
- optimization of interstate pipeline transportation capacity not needed to serve daily load, and
- purchases and sales of natural gas to optimize use of storage capacity.

The following table presents the underlying energy commodity derivative volumes as of March 31, 2014 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWH	Financial (1) MWH	Physical (1) mmBTUs	Financial (1) mmBTUs
2014	725	1,768	18,282	110,762	688	2,522	3,021	87,043
2015	559	1,461	4,973	82,825	222	2,566	1,490	58,210
2016	397	948	2,505	51,950	256	1,634	910	41,490
2017	397	—	675	—	286	—	—	—
2018	397	—	—	—	286	—	—	—
Thereafter	235	—	—	—	158	—	—	—

(1) Physical transactions represent commodity transactions where Avista Utilities will take delivery of either electricity or natural gas and financial transactions represent derivative instruments with no physical delivery, such as futures, swaps or options.

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 delivered and will be included in the various 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 Contracts

A significant portion of Avista Utilities’ 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 Utilities’ short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within sixty days with U.S. dollars. Avista Utilities hedges a portion of the foreign currency risk by purchasing Canadian currency contracts when such commodity transactions are initiated. This risk has not had a material effect on the Company’s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations were included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency hedges that the Company has entered into as of March 31, 2014 and December 31, 2013 (dollars in thousands):

	March 31, 2014	December 31, 2013
Number of contracts	23	23
Notional amount (in United States dollars)	$ 13,128	$ 8,631
Notional amount (in Canadian dollars)	14,596	9,191

Interest Rate Swap Agreements

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. The Finance Committee of the Board of Directors periodically reviews and discusses interest rate risk management processes, and it focuses on the steps management has undertaken to control it. The Risk Management Committee, composed of Company management, also reviews the interest risk management plan. Avista Corp. manages interest rate exposure by limiting the 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 through the use of fixed rate long-term debt with varying maturities. The Company also hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements. These interest rate swaps and U.S. Treasury lock agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the interest rate swaps that the Company has entered into as of March 31, 2014 and December 31, 2013 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
March 31, 2014	2	$ 50,000	2014
	3	60,000	2015
	3	60,000	2016
	2	30,000	2017
	5	115,000	2018
December 31, 2013	2	50,000	2014
	2	45,000	2015
	2	40,000	2016
	1	15,000	2017
	4	95,000	2018

Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

Derivative Instruments Summary

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of March 31, 2014 (in thousands):

		Fair Value						
Derivative	Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet	Gross Assets Not Offset	Gross Liabilities Not Offset	Net Asset (Liability)
Foreign currency contracts	Other current assets	$ 47	$ (30)	$ —	$ 17	$ —	$ —	$ 17
Interest rate contracts	Other current assets	10,619	—	—	10,619	—	—	10,619
Interest rate contracts	Other property and investments - net	10,641	(3,097)	—	7,544	—	—	7,544
Interest rate contracts	Other non-current liabilities and deferred credits	—	(8,906)	2,210	(6,696)	—	—	(6,696)
Commodity contracts (1)	Current utility energy commodity derivative assets	58,483	(41,846)	(2,712)	13,925	—	(158)	13,767
Commodity contracts (1)	Non-current utility energy commodity derivative assets	31,510	(27,965)	—	3,545	—	—	3,545
Commodity contracts (1)	Current utility energy commodity derivative liabilities	1,415	(4,775)	—	(3,360)	—	158	(3,202)
Commodity contracts (1)	Other non-current liabilities and deferred credits	72	(15,271)	—	(15,199)	—	—	(15,199)
Total derivative instruments recorded on the balance sheet		$ 112,787	$ (101,890)	$ (502)	$ 10,395	$ —	$ —	$ 10,395

The following table presents the fair values and locations of derivative instruments recorded on the Condensed Consolidated Balance Sheet as of December 31, 2013 (in thousands):

		Fair Value						
Derivative	Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet	Gross Assets Not Offset	Gross Liabilities Not Offset	Net Asset (Liability)
Foreign currency contracts	Other current assets	$ 7	$ (6)	$ —	$ 1	$ —	$ —	$ 1
Interest rate contracts	Other current assets	13,968	—	—	13,968	—	—	13,968
Interest rate contracts	Other property and investments - net	19,575	—	—	19,575	—	—	19,575
Commodity contracts (1)	Current utility energy commodity derivative assets	7,416	(4,394)	—	3,022	—	—	3,022
Commodity contracts (1)	Non-current utility energy commodity derivative assets	7,610	(6,756)	—	854	—	—	854
Commodity contracts (1)	Current utility energy commodity derivative liabilities	23,455	(37,306)	2,976	(10,875)	—	—	(10,875)
Commodity contracts (1)	Other non-current liabilities and deferred credits	17,101	(41,213)	5,756	(18,356)	—	—	(18,356)
Total derivative instruments recorded on the balance sheet		$ 89,132	$ (89,675)	$ 8,732	$ 8,189	$ —	$ —	$ 8,189

(1) Avista Corp. has a master netting agreement that governs the transactions of multiple affiliated legal entities under this single master netting agreement. This master netting agreement allows for cross-commodity netting (i.e. netting physical power, physical natural gas, and financial transactions) and cross-affiliate netting for the parties to the agreement. Avista Corp. performs cross-commodity netting for each legal entity that is a party to the master netting agreement for presentation in the Condensed Consolidated Balance Sheets; however, Avista Corp. does not perform cross-affiliate netting because the Company believes that cross-affiliate netting may not be enforceable. Therefore, the requirements for cross-affiliate netting under ASC 210-20-45 are not applicable for Avista Corp. As of December 31, 2013, all derivatives for each affiliated entity under this master netting agreement were in a net liability position. As such, there is no additional netting which requires disclosure for that period.

Exposure to Demands for Collateral

The Company'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 the Company's credit ratings or changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements. As of March 31, 2014, the Company had deposited cash in the amount of $2.1 million and letters of credit of $2.5 million as collateral for certain energy derivative contracts. Conversely, the Company holds cash from other counterparties in the amount of $2.7 million as collateral for other energy derivative contracts. The Company also had deposited cash in the amount of $2.2 million as collateral for its interest rate swap derivative contracts. The Condensed Consolidated Balance Sheet at March 31, 2014 reflects the offsetting of $0.5 million of cash collateral against net derivative positions where a legal right of offset exists. As of December 31, 2013, the Company had deposited cash in the amount of $26.1 million and letters of credit of $20.3 million as collateral for certain energy derivative contracts. As of December 31, 2013, the Company did not hold any cash as collateral from counterparties for energy derivative contracts. The Consolidated Balance Sheet at December 31, 2013 reflects the offsetting of $8.7 million of cash collateral against net derivative positions where a legal right of offset exists.

Certain of the Company's derivative instruments contain provisions that require the Company to maintain an "investment grade" credit rating from the major credit rating agencies. If the Company'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 aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of March 31, 2014 was $3.8 million. If the credit-risk-related contingent features underlying these agreements were triggered on March 31, 2014, the Company could be required to post $2.9 million of additional collateral to its counterparties. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2013 was $13.3 million. If the credit-risk-related contingent features underlying these agreements had been triggered on December 31, 2013, the Company could have been required to post $12.6 million of additional collateral to its counterparties.

Credit Risk

Credit risk relates to the potential losses that the Company would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy or make financial settlements. The Company often extends credit to counterparties and customers and is exposed to the risk that it may not be able to collect amounts owed to the Company. Credit risk includes potential counterparty default due to circumstances:

- relating directly to it,
- caused by market price changes, and
- relating to other market participants that have a direct or indirect relationship with such counterparty.

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

The Company enters into bilateral transactions with various counterparties. The Company also trades energy and related derivative instruments through clearinghouse exchanges.

The Company seeks to mitigate bilateral credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring current credit exposures,
- asserting our collateral rights with counterparties,
- carrying out transaction settlements timely and effectively, and
- conducting transactions on exchanges with fully collateralized clearing arrangements that significantly reduce counterparty default risk.

The Company's credit policy includes an evaluation of the financial condition of counterparties. Credit risk management includes collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. The Company enters into various agreements that address credit risks including standardized agreements that allow for the netting or offsetting of positive and negative exposures.

The Company has concentrations of suppliers and customers in the electric and natural gas industries including:

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

In addition, the Company has concentrations of credit risk related to geographic location as it operates in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may impact the Company's overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

The Company maintains credit support agreements with certain counterparties and margin calls are periodically made and/or received. Margin calls are triggered when exposures exceed contractual limits or when there are changes in a counterparty's creditworthiness. Price movements in electricity and natural gas can generate exposure levels in excess of these contractual limits. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

NOTE 6. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The pension and other postretirement benefit plans described below only relate to Avista Utilities and do not cover any of the subsidiary employees. The Company's largest subsidiary, Ecova, has a 401(k) savings plan that is separate from those described below and this plan has historically not been significant to the Company.

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities. Individual benefits under this plan are based upon the employee’s years of service, date of hire and average compensation as specified in the plan. The Company’s funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $11.0 million in cash to the pension plan for the three months ended March 31, 2014. The Company expects to contribute a total of $32.0 million in cash to the pension plan in 2014. The Company contributed $44.3 million in cash to the pension plan in 2013.

In October 2013, the Company revised its defined benefit pension plan such that as of January 1, 2014 the plan is closed to all non-union employees hired or rehired by the Company on or after January 1, 2014. All actively employed non-union employees that were hired prior to January 1, 2014 and are currently covered under the defined benefit pension plan will continue accruing benefits as originally specified in the plan. A new and separate defined contribution 401(k) plan replaced the defined benefit pension plan for all non-union employees hired or rehired on or after January 1, 2014. Under the new defined contribution plan, the Company provides a non-elective contribution as a percentage of each employee's pay based on his or her age. This new defined contribution plan is in addition to the existing 401(k) plan in which the Company matches a portion of the pay deferred by each participant. In addition to the above changes, the Company has also revised its lump sum calculation from its previous lump sum calculation for non-union participants who retire under the defined benefit pension plan to provide non-union retirees on or after January 1, 2014 with a lump sum amount equivalent to the present value of the annuity based upon applicable discount rates. In April 2014, the local union in Oregon for the International Brotherhood of Electrical Workers accepted the above plan changes in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. In October 2013, the Company revised the health care benefit plan such that beginning on January 1, 2020, the method for calculating health insurance premiums for non-union retirees under age 65 and active Company employees was revised. The revisions resulted in separate health insurance premium calculations for each group. In addition, for non-union employees hired or rehired on or after January 1, 2014, upon retirement the Company will provide access to its retiree medical plan, but will no longer provides a contribution towards his or her medical premiums and the employee will pay the full cost of premiums upon retirement. In April 2014, the local union in Oregon for the International Brotherhood of Electrical Workers accepted the above plan changes in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014.

The Company has a Health Reimbursement Arrangement to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on the employee’s years of service and the ending salary. The liability and expense of this plan are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer’s designated beneficiary will receive a payment equal to twice the executive officer’s annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer’s total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

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

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Three months ended March 31:				
Service cost	$ 5,018	$ 4,743	$ 974	$ 1,032
Interest cost	6,706	5,978	1,353	1,390
Expected return on plan assets	(8,110)	(6,900)	(472)	(400)
Amortization of prior service cost	6	75	(43)	(37)
Net loss recognition	1,157	3,547	826	1,521
Net periodic benefit cost	$ 4,777	$ 7,443	$ 2,638	$ 3,506

NOTE 7. COMMITTED LINES OF CREDIT

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400 million. In April 2014, the Company amended this committed line of credit agreement to extend the expiration date to April 2019. The amendment also provides the Company the option to request an extension for an additional one or two years beyond April 2019, provided there is no event of default prior to the requested extension and the requested extension does not cause the remaining term until the expiration date to exceed five years. The amendment did not change the amount of the committed line of credit.

The committed line of credit is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of “consolidated total debt” to “consolidated total capitalization” of Avista Corp. to be greater than 65 percent at any time. As of March 31, 2014, the Company was in compliance with this covenant.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company’s revolving committed lines of credit were as follows as of March 31, 2014 and December 31, 2013 (dollars in thousands):

	March 31, 2014	December 31, 2013
Borrowings outstanding at end of period	$ 111,000	$ 171,000
Letters of credit outstanding at end of period	$ 9,614	$ 27,434
Average interest rate on borrowings at end of period	0.93%	1.02%

As of March 31, 2014 the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Condensed Consolidated Balance Sheet.

Ecova

Ecova has a $125.0 million committed line of credit agreement with various financial institutions that has an expiration date of July 2017. The credit agreement is secured by all of Ecova's assets excluding investments and funds held for clients.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant which requires that Ecova's “Consolidated Total Funded Debt to EBITDA Ratio” (as defined in the credit agreement) must be 2.50 to 1.00 or less, with provisions in the credit agreement allowing for a temporary increase of this ratio if a qualified acquisition is consummated by Ecova. In addition, Ecova's “Consolidated Fixed Charge Coverage Ratio” (as defined in the credit agreement) must be greater than 1.50 to 1.00 as of the last day of any fiscal quarter. As of March 31, 2014, Ecova was in compliance with these covenants.

Balances outstanding and interest rates of borrowings under Ecova's credit agreements were as follows as of March 31, 2014 and December 31, 2013 (dollars in thousands):

	March 31, 2014	December 31, 2013
Borrowings outstanding at end of period	$ 42,000	$ 46,000
Average interest rate on borrowings at end of period	2.16%	2.17%

As of March 31, 2014 the borrowings outstanding under Ecova's committed line of credit were classified as long-term borrowings under committed line of credit on the Condensed Consolidated Balance Sheet.

NOTE 8. LONG-TERM DEBT

The following details long-term debt outstanding as of March 31, 2014 and December 31, 2013 (dollars in thousands):

Maturity Year	Description	Interest Rate	March 31, 2014	December 31, 2013
2016	First Mortgage Bonds	0.84%	$ 90,000	$ 90,000
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
	Total secured long-term debt		1,376,700	1,376,700
	Other long-term debt and capital leases		4,561	4,630
	Settled interest rate swaps (2)		(23,413)	(23,560)
	Unamortized debt discount		(1,246)	(1,287)
	Total		1,356,602	1,356,483
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Current portion of long-term debt		(372)	(358)
	Total long-term debt		$ 1,272,530	$ 1,272,425

(1) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Condensed Consolidated Balance Sheets.

(2) Upon settlement of interest rate swaps, these are recorded as a regulatory asset or liability and included as part of long-term debt above. They are amortized as a component of interest expense over the life of the associated debt and included as a part of the Company's cost of debt calculation for ratemaking purposes.

Nonrecourse Long-Term Debt

Nonrecourse long-term debt (including current portion) represents the long-term debt of Spokane Energy. To provide funding to acquire a long-term fixed rate electric capacity contract from Avista Corp., Spokane Energy borrowed $145.0 million from a funding trust in December 1998. The long-term debt has scheduled monthly installments and interest at a fixed rate of 8.45 percent with the final payment due in January 2015. Spokane Energy bears full recourse risk for the debt, which is secured by the fixed rate electric capacity contract and $1.6 million of funds held in a trust account. As of March 31, 2014, the entire remaining portion of the nonrecourse debt has been included in current liabilities due to its maturity in January 2015.

NOTE 9. FAIR VALUE

The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion, but excluding capital leases), nonrecourse long-term debt and long-term debt to affiliated trusts are reported at carrying value on the Condensed Consolidated Balance Sheets.

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 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, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are 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 that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Condensed Consolidated Balance Sheets as of March 31, 2014 and December 31, 2013 (dollars in thousands):

	March 31, 2014		December 31, 2013	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,080,124	$ 951,000	$ 1,054,512
Long-term debt (Level 3)	342,000	345,980	342,000	329,581
Nonrecourse long-term debt (Level 3)	13,872	14,323	17,838	18,636
Long-term debt to affiliated trusts (Level 3)	51,547	37,052	51,547	37,114

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information. Due to the unique nature of the long-term fixed rate electric capacity contract securing the long-term debt of Spokane Energy (nonrecourse long-term debt), the estimated fair value of nonrecourse long-term debt was determined based on a discounted cash flow model using available market information.

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 March 31, 2014 and December 31, 2013 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
March 31, 2014					
Assets:					
Energy commodity derivatives	$ —	$ 91,090	$ —	$ (73,620)	$ 17,470
Level 3 energy commodity derivatives:					
Power exchange agreement	—	—	390	(390)	—
Foreign currency derivatives	—	47	—	(30)	17
Interest rate swaps	—	21,260	—	(3,097)	18,163
Investments and funds held for clients:					
Money market funds	23,034	—	—	—	23,034
Securities available for sale:					
U.S. government agency	—	54,327	—	—	54,327
Municipal	—	3,109	—	—	3,109
Corporate fixed income – industrial	—	763	—	—	763
Certificate of deposits	—	1,000	—	—	1,000
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	1,906	—	—	—	1,906
Equity securities (2)	6,475	—	—	—	6,475
Total	$ 33,015	$ 171,596	$ 390	$ (77,137)	$ 127,864
Liabilities:					
Energy commodity derivatives	$ —	$ 72,997	$ —	$ (70,908)	$ 2,089
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	2,418	—	2,418
Power exchange agreement	—	—	14,014	(390)	13,624
Power option agreement	—	—	428	—	428
Foreign currency derivatives	—	30	—	(30)	—
Interest rate swaps	—	12,003	—	(5,307)	6,696
Total	$ —	$ 85,030	$ 16,860	$ (76,635)	$ 25,255

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2013					
Assets:					
Energy commodity derivatives	$ —	$ 55,243	$ —	$ (51,367)	$ 3,876
Level 3 energy commodity derivatives:					
Power exchange agreement	—	—	339	(339)	—
Foreign currency derivatives	—	7	—	(6)	1
Interest rate swaps	—	33,543	—	—	33,543
Investments and funds held for clients:					
Money market funds	11,180	—	—	—	11,180
Securities available for sale:					
U.S. government agency	—	61,078	—	—	61,078
Municipal	—	3,518	—	—	3,518
Corporate fixed income – financial	—	3,000	—	—	3,000
Corporate fixed income – industrial	—	765	—	—	765
Certificate of deposits	—	1,000	—	—	1,000
Funds held in trust account of Spokane Energy	1,600	—	—	—	1,600
Deferred compensation assets:					
Fixed income securities (2)	1,960	—	—	—	1,960
Equity securities (2)	6,470	—	—	—	6,470
Total	$ 21,210	$ 158,154	$ 339	$ (51,712)	$ 127,991
Liabilities:					
Energy commodity derivatives	$ —	$ 72,895	$ —	$ (60,099)	$ 12,796
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,219	—	1,219
Power exchange agreement	—	—	14,780	(339)	14,441
Power option agreement	—	—	775	—	775
Foreign currency derivatives	—	6	—	(6)	—
Total	$ —	$ 72,901	$ 16,774	$ (60,444)	$ 29,231

(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) These assets are trading securities and are included in other property and investments-net on the Condensed Consolidated Balance Sheets.

Avista Corp. enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of Avista Corp.'s management of loads and resources and certain contracts are considered derivative instruments. The difference between the amount of derivative assets and liabilities disclosed in respective levels and the amount of derivative assets and liabilities disclosed on the Condensed Consolidated Balance Sheets is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using broker quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using broker quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

For securities available for sale (held at Ecova) Ecova uses a nationally recognized third party to obtain fair value and reviews these prices for accuracy using a variety of market tools and analyses. Ecova's pricing vendor uses a generic model which uses standard inputs, including (listed in order of priority for use) benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, market bids/offers and other reference data. The pricing vendor also monitors market indicators, as well as industry and economic events. All securities available for sale were deemed Level 2.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.9 million as of March 31, 2014 and $0.7 million as of December 31, 2013.

Level 3 Fair Value

For the power exchange agreement, the Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average operating and maintenance (O&M) charges from four surrogate nuclear power plants around the country for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For the power commodity option agreement, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges, 2) estimated delivery volumes for years beyond 2013, and 3) volatility rates for periods beyond April 2017. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility assumptions used in the calculation.

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered 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 have not been 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 March 31, 2014 (dollars in thousands):

	Fair Value (Net) at March 31, 2014	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (13,624)	Surrogate facility pricing	O&M charges	$30.18-$53.90/MWh (1)
			Escalation factor	3% - 2014 to 2019
			Transaction volumes	396,984 - 397,116 MWhs
Power option agreement	(428)	Black-Scholes-Merton	Strike price	$56.53/MWh - 2016
				$69.98/MWh - 2015
			Delivery volumes	128,278 - 286,307 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(2,418)	Internally derived weighted average cost of gas	Forward purchase prices	$3.66 - $4.45/mmBTU
			Forward sales prices	$4.54 - $5.23/mmBTU
			Purchase volumes	280,000 - 310,000 mmBTUs
			Sales volumes	279,990 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2013 were $40.93 per MWh. For ratemaking purposes the average O&M calculations vary slightly between regulatory jurisdictions. The average O&M charges for the delivery year beginning in 2013 were $42.44 for Washington and $40.93 for Idaho.

(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.31 for 2014 to 0.18 in April 2017.

Avista Corp.'s risk management team and accounting team are responsible for developing the valuation methods described above and both groups report to the Chief Financial Officer. The valuation methods, significant inputs and resulting fair values described above are reviewed on at least a quarterly basis by the risk management team and the accounting team to ensure they provide a reasonable estimate of fair value each reporting period.

The following table presents activity for energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the three months ended March 31 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Three months ended March 31, 2014:				
Balance as of January 1, 2014	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	1,849	2,026	347	4,222
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(3,048)	(1,209)	—	(4,257)
Transfers to/from other categories	—	—	—	—
Ending balance as of March 31, 2014	$ (2,418)	$ (13,624)	$ (428)	$ (16,470)
Three months ended March 31, 2013:				
Balance as of January 1, 2013	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	750	24	280	1,054
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(362)	2,205	—	1,843
Transfers from other categories	—	—	—	—
Ending balance as of March 31, 2013	$ (1,991)	$ (16,463)	$ (1,200)	$ (19,654)

(1) The UTC and the IPUC issued accounting orders authorizing Avista Corp. to offset 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. The orders provide for Avista Corp. to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Condensed Consolidated Statements of Income. Realized gains or losses are recognized in the period of delivery, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

NOTE 10. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION SHAREHOLDERS

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corporation shareholders for the three months ended March 31 (in thousands, except per share amounts):

	2014	2013
Numerator:		
Net income attributable to Avista Corporation shareholders	$ 48,499	$ 42,341
Subsidiary earnings adjustment for dilutive securities	(53)	(43)
Adjusted net income attributable to Avista Corporation shareholders for computation of diluted earnings per common share	$ 48,446	$ 42,298
Denominator:		
Weighted-average number of common shares outstanding-basic	60,122	59,866
Effect of dilutive securities:		
Performance and restricted stock awards	46	32
Weighted-average number of common shares outstanding-diluted	60,168	59,898
Earnings per common share attributable to Avista Corporation shareholders:		
Basic	$ 0.81	$ 0.71
Diluted	$ 0.81	$ 0.71

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

NOTE 11. 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 intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Utilities' operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp. doing business as Avista Utilities, Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Utilities or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). Appeals of the FERC's decisions approving the Agreement in Resolution are pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). In May 2004, the FERC provided notice that Avista Energy was no longer subject to an investigation reviewing certain bids above $250 per MW in the short-term energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) from May 1, 2000 to October 2, 2000 (Bidding Investigation). Appeal of this FERC decision is also pending before the Ninth Circuit.

As discussed in "California Refund Proceeding" below, on March 7, 2014, Avista Utilities and Avista Energy filed at FERC a settlement with Pacific Gas & Electric (PG&E), Southern California Edison, San Diego Gas & Electric, the California Attorney General (AG), the California Department of Water Resources (CERS), and the California Public Utilities Commission (together, the "California Parties") that resolves, inter alia, both the Trading Investigation and the Bidding Investigation. The settlement is subject to FERC's approval. The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The

FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In 2011, the FERC approved Avista Energy’s cost filing, a decision that is now before the Ninth Circuit.

In August 2006, the Ninth Circuit remanded to the FERC its decision not to consider an FPA section 309 remedy for tariff violations prior to October 2, 2000. In May 2011, the FERC clarified the issues set for hearing for the period May 1, 2000 - October 1, 2000 (Summer Period): (1) which market practices and behaviors constitute a violation of the then-current CalISO, CalPX, and individual seller's tariffs and FERC orders; (2) whether any of the sellers named as respondents in this proceeding engaged in those tariff violations; and (3) whether any such tariff violations affected the market clearing price. The FERC also gave the claimants an opportunity to show that exchange transactions with the CalISO during the Refund Period were not just and reasonable. During a FERC hearing in 2012, the Presiding Administrative Law Judge (ALJ) issued a partial initial decision granting Avista Utilities' motion for summary disposition, based on the stipulation by the parties that there are no allegations of tariff violations made against Avista Utilities in this proceeding and therefore no tariff violations by Avista Utilities that affected the market clearing price in any hour during the Summer Period. On November 2, 2012, the FERC issued an order affirming the partial initial decision and dismissing Avista Utilities from the proceeding, thereby terminating all claims against Avista Utilities for the Summer Period. In the same order, the FERC also held that a market-wide remedy would not be appropriate with regard to any respondent during the Summer Period. On February 15, 2013, the ALJ issued an initial decision ruling that the claimants met their burden in the case against Avista Energy by relying on “screens” that identified transactions that potentially could have signified tariff violations. The initial decision did not discuss evidence offered by Avista Energy, on an hour-by-hour basis, rebutting the alleged violations. With respect to Avista Energy's one exchange transaction with the CalISO during the Refund Period, the judge made no findings with respect to the justness and reasonableness of that transaction, but nonetheless determined that Avista Energy owed approximately $0.2 million in refunds with regard to the transaction.

On March 7, 2014, Avista Utilities, Avista Energy and the California Parties filed a settlement at the FERC that would resolve these matters. The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX, and as a result, Avista Energy has not been paid for all of its sales during the Refund Period. Those funds have been held in escrow accounts pending resolution of this proceeding. The settlement, which is pending the FERC's approval, would return $15 million of Avista Energy’s receivable to Avista Energy, with the balance of the Avista Energy receivable flowing to the purchasers associated with the hourly transactions at issue. There is no admission of wrongdoing on the part of the settling parties, and thus it is further agreed that no part of the refund payment by Avista Energy constitutes a fine or a penalty. The settlement resolves all claims for alleged overcharges during the Summer and Refund Periods in the California Refund Proceeding, and in the Pacific Northwest Refund Proceeding (for sales made to CERS), as discussed below. The settlement also includes settlement of the Trading Investigation, the Bidding Investigation and the California Attorney General Complaint (the "Lockyer Complaint").

The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. The Ninth Circuit expressly declined to direct the FERC to grant refunds. On October 3, 2011, the FERC issued an Order on Remand, finding that, in light of the Ninth Circuit's remand order, additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest spot market during the period from December 25, 2000 through June 20, 2001. The Order on Remand established an evidentiary, trial-type hearing before an ALJ, and reopened the record to permit parties to present evidence of unlawful market activity. The Order on Remand stated that parties seeking refunds must submit evidence demonstrating that specific unlawful market activity occurred, and must demonstrate that such activity directly affected negotiations with respect to the specific contract rate about which they complain. Simply alleging a general link between the dysfunctional spot market in California and the Pacific Northwest spot market will not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue.

On July 11, 2012, Avista Energy and Avista Utilities filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma, which the FERC approved. The two remaining direct claimants against Avista Utilities and Avista Energy in this proceeding are the City of Seattle, Washington (Seattle), and the California AG (on behalf of CERS).

On April 5, 2013, the FERC issued an Order on Rehearing expanding the temporal scope of the proceeding to permit parties to submit evidence on transactions during the period from January 1, 2000 through and including June 20, 2001.

On April 11, 2013, certain of the California Parties filed a petition for review of the October 3, 2011 Order on Remand, and the April 5, 2013 Order on Rehearing, in the Ninth Circuit. Seattle filed a petition for review of the same orders on April 26, 2013.

The hearing before an ALJ began on August 27, 2013.

As discussed in "California Refund Proceeding" above, on March 7, 2014, the Company and the California Parties filed at the FERC a settlement that encompasses the CERS claims in this proceeding, obviating the need for additional litigation.

With regard to the Seattle claims, on March 28, 2014, the Presiding ALJ issued her initial decision finding that: (1) Seattle failed to demonstrate that either Avista Utilities or Avista Energy engaged in unlawful market activity and also failed to identify any specific contracts at issue; (2) Seattle failed to demonstrate that contracts with either Avista Utilities or Avista Energy imposed an excessive burden on consumers or seriously harmed the public interest; and that (3) Seattle failed to demonstrate that either Avista Utilities or Avista Energy engaged in any specific violations of substantive provisions of the Federal Power Act or any filed tariffs or rate schedules. Accordingly, the ALJ denied all of Seattle’s claims under both section 206 and section 309 of the Federal Power Act. Briefs on exceptions are due May 12, 2014 and briefs opposing exceptions are due June 16, 2014. The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

California Attorney General Complaint (the “Lockyer Complaint”)

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the California AG that alleged violations of the FPA by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's adoption and implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint. In September 2004, the Ninth Circuit upheld the FERC's market-based rate authority, but held that the FERC erred in ruling that it lacked authority to order refunds for violations of its reporting requirement. The Court remanded the case for further proceedings, which ultimately resulted in summary disposition at the FERC in favor of Avista Utilities and Avista Energy. The proceeding is now before the Ninth Circuit.

As discussed in "California Refund Proceeding" above, on March 7, 2014, Avista Utilities, Avista Energy and the California Parties filed a settlement at the FERC that resolves these matters. The settlement is subject to approval by the FERC. The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Litigation

On March 6, 2013, the Sierra Club and Montana Environmental Information Center (MEIC) (collectively "Plaintiffs"), filed a Complaint in the United States District Court for the District of Montana, Billings Division, against the Owners of the Colstrip Generating Project ("Colstrip"). Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The other Colstrip co-Owners are PPL Montana, Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Complaint alleges certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements. The Plaintiffs request that the Court grant injunctive and declaratory relief, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees.

On May 3, 2013, the Colstrip Owners filed a Partial Motion to Dismiss, seeking dismissal of 36 of the 39 claims. The Plaintiffs filed their opposition on May 31, 2013, and the Owners filed their reply on June 21, 2013. On July 17, 2013, the Court held a preliminary pretrial conference, and on July 18, 2013, the Court issued an Order establishing a procedural schedule and deadlines.

On September 12, 2013, the Plaintiffs filed Plaintiffs’ First Motion for Partial Summary Judgment on the Applicable Method for Calculating Emission Increases from Modifications Made to the Colstrip Power Plant. The Colstrip Owners filed their opposition on November 15, 2013. On November 19, 2013, the Court issued an Order granting the Montana Department of Environmental Quality permission to file an amicus brief concerning Plaintiffs' Motion.

On September 27, 2013, the Plaintiffs filed an Amended Complaint. The Amended Complaint withdrew from the original Complaint fifteen claims related to seven pre-January 1, 2001 Colstrip maintenance projects, upgrade projects and work projects and claims alleging violations of Title V and opacity requirements. The Amended Complaint alleges certain violations of the Clean Air Act and the New Source Review and adds claims with respect to post-January 1, 2001 Colstrip projects. The Plaintiffs request that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damage, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees.

On October 11, 2013, the Colstrip Owners filed a Motion to Dismiss, seeking dismissal of all of Plaintiffs' claims contained in the Amended Complaint.

On January 23, 2014, the Court issued an Order amending the procedural schedule and deadlines.

On April 18, 2014, the Court issued an Order setting May 6, 2014 as the date the Court will hear oral argument on the Colstrip Owners' Motion to Dismiss and Plaintiffs' Motion for Partial Summary Judgment.

Due to the preliminary nature of the lawsuit, Avista Corporation cannot, at this time, predict the outcome of the matter.

Spokane River Licensing

The Company owns and operates six hydroelectric plants on the Spokane River. Five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls) are regulated under one 50-year FERC license issued in June 2009 and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the United States Department of Interior and the Coeur d'Alene Tribe, as well as the mandatory conditions that were agreed to in the Idaho 401 Water Quality Certifications and in the amended Washington 401 Water Quality Certification.

As part of the Settlement Agreement with the Washington Department of Ecology (Ecology), the Company has participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, Ecology filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company's level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company submitted a draft Water Quality Attainment Plan for Dissolved Oxygen to Ecology in May 2012 and this was approved by Ecology in September 2012. This plan was subsequently approved by the FERC. The Company began implementing this plan in 2013, and management believes costs will not be material. On July 16, 2010, the City of Post Falls and the Hayden Area Regional Sewer Board filed an appeal with the United States District Court for the District of Idaho with respect to the EPA's approval of the TMDL. The Company, the City of Coeur d'Alene, Kaiser Aluminum and the Spokane River Keeper subsequently moved to intervene in the appeal. In September 2011, the EPA issued a stay to the litigation that will be in effect until either the permits are issued and all appeals and challenges are complete or the court lifts the stay. The stay is still in effect.

During 2013, through a collaborative process with key stakeholders, a decision was reached to not move forward with a specific capital project to add oxygen to Lake Spokane. At the time of such decision, the Company had expended $1.3 million on the discontinued project. On September 26, 2013 and October 23, 2013, the UTC and IPUC, respectively, issued Orders approving the Company's petition for an accounting order authorizing deferral of costs related to the discontinued project. The Washington portion of the project costs were $0.9 million and the Idaho portion were $0.5 million and these costs have been recorded as regulatory assets. The Company intends to seek recovery of these costs through the ratemaking process.

The UTC and IPUC approved the recovery of licensing costs through the general rate case settlements in 2009. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to implementing the license for the Spokane River Project.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels in the Clark Fork River exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. In the second quarter of 2011, the Company completed preliminary feasibility assessments for several alternative abatement measures. In 2012, Avista Corp., with the approval of the Clark Fork Management Committee (created under the Clark Fork Settlement Agreement), moved forward to test one of the alternatives by constructing a spill crest modification on a single spill gate. Based on testing in 2013, the modification appears to provide significant Total Dissolved Gas reduction. Ongoing design improvements have been made, and the Company expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the United States Fish and Wildlife Service (USFWS) listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Fishway designs for Cabinet Gorge are still being finalized. Construction cost estimates and schedules will be developed after several remaining issues are resolved, related to Montana's approval of fish transport from Idaho and expected minimum discharge requirements. Fishway design for Noxon Rapids has also been initiated, and is still in early stages.

In January 2010, the USFWS revised its 2005 designation of critical habitat for the bull trout to include the lower Clark Fork River as critical habitat. The Company believes its ongoing efforts through the Clark Fork Settlement Agreement continue to effectively address issues related to bull trout. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Kettle Falls Generation Station - Diesel Spill Investigation and Remediation

On December 24, 2013, the Company's operations staff at the Kettle Falls Generation Station discovered that approximately 10,000 gallons of diesel fuel had leaked underground from the piping system used to fuel heavy equipment. Avista Corp. made all proper agency notifications and worked closely with the Washington State Department of Ecology (Ecology) during the spill response and investigation phase. The Company installed down gradient monitoring wells and there is no indication that ground or surface water is threatened by the spill.

The Company plans to implement a voluntary cleanup action and there is no indication from Ecology that Ecology is considering any enforcement action. The Company is developing a request for proposal for the most effective remediation system.

As of March 31, 2014, the Company has recorded an estimated remediation liability and the Company will continue to monitor the remediation activities and will adjust any estimated remediation liability if necessary as new information is obtained. The Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

Collective Bargaining Agreements

The Company’s collective bargaining agreement with the International Brotherhood of Electrical Workers represents approximately 45 percent of all of Avista Utilities’ employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expired in March 2014. A new three-year agreement in Oregon, which covers approximately 50 employees, was approved in April 2014. Negotiations are currently ongoing with respect to the expired labor agreement in Washington and Idaho and the Company does not expect any disruption to its operations.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that 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 that 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.

NOTE 12. 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) attributable to Avista Corp. shareholders. 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. Ecova is a provider of facility information and cost management services for multi-site customers throughout North America. The Other category, which is not a reportable segment, includes Spokane Energy, 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	Ecova	Other	Total Non-Utility	Intersegment Eliminations (1)	Total
For the three months ended March 31, 2014:						
Operating revenues	$ 437,574	$ 44,384	$ 9,454	$ 53,838	$ (450)	$ 490,962
Resource costs	220,497	—	—	—	—	220,497
Other operating expenses	67,337	37,877	9,833	47,710	(450)	114,597
Depreciation and amortization	30,726	3,709	147	3,856	—	34,582
Income (loss) from operations	90,868	2,798	(526)	2,272	—	93,140
Interest expense (2)	18,546	340	397	737	(88)	19,195
Income taxes	27,620	894	(338)	556	—	28,176
Net income (loss) attributable to Avista Corporation shareholders	47,996	1,111	(608)	503	—	48,499
Capital expenditures	59,725	3,883	46	3,929	—	63,654
For the three months ended March 31, 2013:						
Operating revenues	$ 431,577	$ 42,407	$ 9,372	$ 51,779	$ (450)	$ 482,906
Resource costs	229,630	—	—	—	—	229,630
Other operating expenses	65,444	35,990	9,795	45,785	(450)	110,779
Depreciation and amortization	27,935	3,493	190	3,683	—	31,618
Income (loss) from operations	82,751	2,924	(613)	2,311	—	85,062
Interest expense (2)	18,770	444	673	1,117	(77)	19,810
Income taxes	24,780	984	(528)	456	—	25,236
Net income (loss) attributable to Avista Corporation shareholders	42,250	1,198	(1,107)	91	—	42,341
Capital expenditures	70,645	794	25	819	—	71,464
Total Assets:						
As of March 31, 2014:	$ 3,893,474	$ 344,828	$ 77,776	$ 422,604	$ —	$ 4,316,078
As of December 31, 2013:	$ 3,940,998	$ 339,643	$ 81,282	$ 420,925	$ —	$ 4,361,923

(1) Intersegment eliminations reported as operating revenues and resource costs represent intercompany purchases and sales of electric capacity and energy. Intersegment eliminations reported as interest expense represent intercompany interest.

(2) Including interest expense to affiliated trusts.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Avista Corporation
Spokane, Washington

We have reviewed the accompanying condensed consolidated balance sheet of Avista Corporation and subsidiaries (the "Company") as of March 31, 2014, and the related condensed consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for the three-month periods ended March 31, 2014 and 2013. These interim financial statements are the responsibility of the Company's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 Public Company Accounting Oversight Board (United States), 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.

Based on our reviews, we are not aware of any material modifications that should be made to such condensed consolidated interim financial statements for them 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), the consolidated balance sheet of Avista Corporation and subsidiaries as of December 31, 2013, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for the year then ended (not presented herein); and in our report dated February 26, 2014, 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, 2013 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

Seattle, Washington
May 7, 2014

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

Business Segments

We have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. that comprises our regulated utility operations. Avista Utilities generates, transmits and distributes electricity and distributes natural gas, serving electric and gas customers in eastern Washington and northern Idaho and gas customers in parts of Oregon. The utility also engages in wholesale purchases and sales of electricity and natural gas.
- **Ecova** – an indirect subsidiary of Avista Corp. (80.2 percent owned as of March 31, 2014) that provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova's service lines include expense management services for utility and telecom needs as well as strategic energy management and efficiency services that include procurement, conservation, performance reporting, financial planning, facility optimization and continuous monitoring, and energy efficiency program management for commercial enterprises and utilities.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, as well as certain other operations of Avista Capital. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp., including AM&D, doing business as METALfx.

The following table presents net income (loss) attributable to Avista Corp. shareholders for each of our business segments (and the other businesses) for the three months ended March 31 (dollars in thousands):

	2014	2013
Avista Utilities	$ 47,996	$ 42,250
Ecova	1,111	1,198
Other	(608)	(1,107)
Net income attributable to Avista Corporation shareholders	$ 48,499	$ 42,341

Executive Level Summary

Overall Results

Net income attributable to Avista Corporation shareholders was $48.5 million for the three months ended March 31, 2014, an increase from $42.3 million for the three months ended March 31, 2013. This was due to an increase in earnings at Avista Utilities, a decrease in losses at the other businesses, partially offset by a slight decrease in earnings at Ecova. Earnings at Avista Utilities increased primarily due to the implementation of general rate increases in all our jurisdictions and colder weather, partially offset by expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes. Net income at Ecova decreased slightly due to higher other operating expenses and increased depreciation and amortization partially offset by increased revenues from energy management services. These results, including a quantification of their respective impacts, are discussed in detail below under "Results of Operations."

Avista Utilities

Avista Utilities is our most significant business segment. Our utility financial performance is dependent upon, among other things:

- weather conditions (temperatures, precipitation levels and wind patterns) which affect energy demand and electric generation, including the effect of precipitation and temperature on hydroelectric resources, the effect of wind patterns on wind-generated power, weather-sensitive customer demand, and similar impacts on supply and demand in the wholesale energy markets,
- regulatory decisions, allowing our utility to recover costs, including purchased power and fuel costs, on a timely basis, and to earn a reasonable return on investment,
- the price of natural gas in the wholesale market, including the effect on the price of fuel for generation, and
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand.

General Rate Cases

In our utility operations, we regularly review the need for rate changes in each jurisdiction to improve the recovery of costs and capital investments in our generation, transmission and distribution systems. The following are the recent general rate increases that have occurred or will go into effect in the near future.

Jurisdiction	Service	Effective Date
Washington	Electric and Natural Gas	January 1, 2013 (1) (3)
	Electric and Natural Gas	January 1, 2014 (1) (3)
Idaho	Natural Gas	April 1, 2013 (2) (3)
	Electric and Natural Gas	October 1, 2013 (2) (3)
Oregon	Natural Gas	February 1, 2014 (4)
	Natural Gas	November 1, 2014 (4)

(1) Relates to a settlement agreement in our Washington general rate cases (originally filed on April 2, 2012), which was approved by the UTC in December 2012 (see further discussion below under "Washington General Rate Cases").

(2) Relates to a settlement agreement in our Idaho general rate cases (originally filed on October 11, 2012), which was approved by the IPUC in March 2013 (see further discussion below under "Idaho General Rate Cases").

(3) Included in the original settlement agreements is a provision that we will not file a general rate case in these jurisdictions seeking new rates to take effect before January 1, 2015. We filed general rate cases in Washington in February 2014 and we are evaluating the need to file general rate cases in Idaho in 2014 with proposed rates that would take effect on or after January 1, 2015. This provision does not preclude us from filing other rate adjustments such as PGAs.

(4) Relates to a settlement agreement in our Oregon general rate case (originally filed in August 2013), which was approved by the OPUC in January 2014 (see further discussion below under "Oregon General Rate Case").

Capital Expenditures

We are making significant capital investments in generation, transmission and distribution systems to preserve and enhance service reliability for our customers and replace aging infrastructure. Utility capital expenditures were $59.7 million for the three months ended March 31, 2014. We expect utility capital expenditures to be about $335 million for 2014, $355 million for 2015, and $350 million for 2016. These estimates of capital expenditures are subject to continuing review and adjustment (see discussion under “Avista Utilities Capital Expenditures”).

Alaska Energy and Resources Company Planned Transaction

On November 4, 2013, we entered into an agreement and plan of merger (Merger Agreement) with AERC, a privately-held company based in Juneau, Alaska. If all necessary approvals are received, when the transaction is complete, AERC will become a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is AEL&P, a regulated utility which provides electric services to approximately 16,000 customers in the City and Borough of Juneau, Alaska. In 2013, AEL&P had annual revenues of $42.6 million and a total rate base of $109.0 million. The utility has a firm retail peak load of approximately 68 MW. AEL&P owns four hydroelectric generating facilities, having a total present capacity of 24.7 MW, and has a power purchase commitment for the output of the Snettisham hydroelectric project, having a present capacity of 78 MW, for a total hydroelectric capacity of 102.7 MW. AEL&P is not interconnected to any other electric system. The utility also has 93.9 MW of diesel generating capacity to provide back-up service to firm customers when necessary.

In addition to the regulated utility, AERC owns 100 percent of AJT Mining, which is an inactive mining company holding certain properties.

The merger consideration at closing will be $170 million, less AERC's indebtedness and subject to other customary closing adjustments. The transaction will be funded primarily through the issuance of Avista Corp. common stock to the shareholders of AERC. The transaction is expected to close by July 1, 2014, following the approval of the merger transaction by the requisite number of AERC shareholders, the receipt of necessary regulatory approvals and the satisfaction of other closing conditions. Avista Corp. shareholder approval is not required. We expect that the addition of AERC will be slightly dilutive to earnings per share in 2014, and that it will be slightly accretive to earnings per share in 2015 and beyond.

The transaction is expected to result in the recording of goodwill, currently estimated at $48 million.

AEL&P currently has an authorized utility capital structure of 53.8 percent equity and an authorized return on equity of 12.875 percent. We expect that AEL&P will maintain this capital structure following the merger. The consolidated capital structure of AERC is expected to be similar to the capital structure of Avista Corp.

For additional information regarding the AERC transaction, including the valuation and number of shares of Avista Corp. common stock to be delivered to AERC shareholders, see “Note 4 of the Notes to Condensed Consolidated Financial Statements” and our Current Report on Form 8-K dated November 4, 2013.

Ecova

Ecova plans to continue to grow organically and possibly through strategic acquisitions. Ecova's acquisitions since 2008 have been funded through internally generated cash, borrowings under Ecova's credit facility and an equity infusion from existing shareholders. If Ecova's capital needs exceed its credit facility capacity or management determines a different capital structure is necessary, Ecova may require additional equity infusions from existing shareholders and/or new funding sources.

We are in the process of exploring the possibility of selling our interest in Ecova. We have received offers that we are evaluating. However, there is no assurance that the terms of any proposed transaction will ultimately be acceptable to the Company, that the conditions to any proposed transaction will be satisfied or that any proposed transaction will be completed. If no such transaction is completed, we will continue to support Ecova's growth initiatives. The value of any potential sales transaction will depend on market conditions, transaction structure and other factors.

Liquidity and Capital Resources

We have a committed line of credit with various financial institutions in the total amount of $400.0 million. In April 2014, we amended this committed line of credit agreement to extend the expiration date to April 2019. The amendment also provides us with the option to request an extension for an additional one or two years beyond April 2019, provided there is no event of default prior to the requested extension and the requested extension does not cause the remaining term until the expiration date to exceed five years. The amendment did not change the amount of the committed line of credit. As of March 31, 2014, there were $111.0 million of cash borrowings and $9.6 million in letters of credit outstanding leaving $279.4 million of available liquidity under this line of credit.

Ecova has a committed line of credit agreement in the total amount of $125.0 million with various financial institutions with an expiration date of July 2017. As of March 31, 2014, Ecova had $42.0 million of borrowings outstanding under its committed line of credit agreement. Based on certain covenant conditions contained in the credit agreement, at March 31, 2014, Ecova could borrow an additional $38.8 million and still be compliant with the covenants. The covenant restrictions are calculated on a rolling twelve month basis, so this additional borrowing capacity could increase or decrease or Ecova could be required to pay down the outstanding debt as future results change. See further discussion of the specific covenants below under "Ecova Credit Agreement."

We expect to issue approximately $190.0 million of long-term debt during 2014, including about $90.0 million of debt issuances combined between AERC or AEL&P associated with rebalancing the consolidated capital structure at AERC. This amount assumes we are going to refinance the existing net debt of AEL&P, estimated to be about $25.0 million at closing. The net debt outstanding at AEL&P does not include the Snettisham obligation which had a balance of $72.1 million as of December 31, 2013, as this relates to a power purchase commitment for which AEL&P has recorded a long-term power purchase asset and corresponding liability. In addition to rebalancing the consolidated capital structure at AERC, the proceeds from the issuance of long-term debt will be used to repay a portion of short-term borrowings, fund utility capital expenditures and other contractual commitments at Avista Corp.

We are party to two sales agency agreements for the sale from time to time of shares of our common stock; however, we do not plan to issue any shares under these agreements during 2014 due to the planned AERC transaction.

In the three months ended March 31, 2014, we issued $0.6 million (net of issuance costs) of common stock under the dividend reinvestment and direct stock purchase plan, and employee plans. For 2014, we expect to issue approximately $145.0 million of common stock related to closing the planned transaction. Without the planned transaction, Avista Corp. would have issued common stock to maintain an appropriate capital structure. Assuming the transaction is completed, we will not need to issue any common stock under the sales agency agreements referred to above in 2014.

Included in our 2014 liquidity estimates is approximately $50.0 million of lower tax payments due to the planned adoption of federal tax tangible property regulations. This will be accomplished through an accounting method change filing with the Internal Revenue Service that will retroactively modify which tangible property transactions we expense versus capitalize and depreciate for federal tax purposes.

After considering the expected issuances of long-term debt and common stock during 2014 and the lower tax payments from the adoption of the federal tax tangible property regulations, we expect net cash flows from operating activities, together with cash available under our $400.0 million committed line of credit agreement, to provide adequate resources to fund capital expenditures, dividends, and other contractual commitments.

Avista Utilities – Regulatory Matters

General Rate Cases

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

- seek recovery of operating costs and capital investments, and
- seek the opportunity to earn 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.

Washington General Rate Cases

A settlement agreement approved by the UTC in December 2011 regarding electric and natural gas general rate cases filed in May 2011 provided for the deferral of certain generation plant maintenance costs. For 2011 and 2012 the Company compared actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and deferred the difference. This deferral occurred each year, with no carrying charge, with deferred costs to be amortized over a four-year period, beginning in the year following the period costs are deferred. Total net deferred costs under this mechanism in Washington were a regulatory asset of $2.8 million as of March 31, 2014 compared to $3.1 million as of December 31, 2013. As part of the settlement agreement to our latest general rate case approved in December 2012, the parties agreed to terminate the maintenance cost deferral mechanism on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

In December 2012, the UTC approved a settlement agreement in our electric and natural gas general rate cases filed in April 2012. The settlement, effective January 1, 2013, provided that base rates for our Washington electric customers increase by an overall 3.0 percent (designed to increase annual revenues by $13.6 million), and base rates for our Washington natural gas customers increase by an overall 3.6 percent (designed to increase annual revenues by $5.3 million). Under the settlement, there was a one-year credit designed to return $4.4 million to electric customers from the existing ERM deferral balance so the net average electric rate increase to our customers in 2013 was 2.0 percent. The credit to customers from the ERM balance did not impact our earnings.

The approved settlement also provided that, effective January 1, 2014, base rates increased for our Washington electric customers by an overall 3.0 percent (designed to increase annual revenues by $14.0 million), and for our Washington natural gas customers by an overall 0.9 percent (designed to increase annual revenues by $1.4 million). The settlement provides for a one-year credit designed to return $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase to our customers effective January 1, 2014 was 2.0 percent. The credit to customers from the ERM balance will not impact our earnings. The ERM balance as of March 31, 2014 was a liability of $15.8 million.

The settlement agreement provides for an authorized return on equity of 9.8 percent and an equity ratio of 47 percent, resulting in an overall rate of return on rate base of 7.64 percent.

The December 2012 UTC Order approving the settlement agreement included certain conditions.

(1) The new retail rates that became effective on January 1, 2014 are temporary rates, and on January 1, 2015 electric and natural gas base rates will revert back to 2013 levels absent any intervening action from the UTC. The original settlement agreement has a provision that we will not file a general rate case in Washington seeking new rates to take effect before January 1, 2015.

(2) In its Order, the UTC found that much of the approved base rate increase is justified by the planned capital expenditures necessary to upgrade and maintain our utility facilities. If these capital projects are not completed to a level that was contemplated in the settlement agreement, this could result in base rates which are considered too high by the UTC. We are required to file capital expenditure progress reports with the UTC on a periodic basis so that the UTC can monitor the capital expenditures and ensure they are in line with those contemplated in the settlement agreement. Total utility capital expenditures among all jurisdictions were $294.4 million for 2013. We expect utility capital expenditures to be about $335 million for 2014, and $355 million for 2015, which are above the capital expenditures contemplated in the

settlement agreement.

On February 4, 2014 we filed electric and natural gas general rates cases with the UTC. We have requested an overall increase in base electric rates of 3.8 percent (designed to increase annual electric revenues by $18.2 million) and an overall increase in base natural gas rates of 8.1 percent (designed to increase annual natural gas revenues by $12.1 million). Our requests are based on a proposed overall rate of return of 7.71 percent, with a common equity ratio of 49.0 percent and a 10.1 percent return on equity.

We have also proposed a rebate beginning January 1, 2015, related to our sale of renewable energy credits (REC) that would reduce customers' monthly electric bills by 1.1 percent. The rebate associated with the sale of RECs is in response to the UTC Order approving our previous general rate case settlement in December 2012. This proposed REC rebate would commence simultaneously with the expiration of two rebates that, together, are currently reducing customers' monthly electric bills by 2.8 percent. The net effect, commencing January 1, 2015, of the proposed new 1.1 percent rebate and the expiration of the current 2.8 percent rebate would be an increase in monthly electric bills of approximately 1.7 percent from 2014 levels. These rebates do not increase or decrease our earnings.

The combination of the 3.8 percent requested increase in base electric rates and the effective 1.7 percent increase attributable to the rebates would be a 5.5 percent increase in electric billings.

As part of our electric and natural gas general rate case filings, we have requested the implementation of decoupling mechanisms, which would sever the link between actual volumetric sales and the recovery of our fixed costs. Under the proposed decoupling mechanisms, we would compare actual non-power supply (electric) and non-PGA (natural gas) revenue to the allowed non-power supply and non-PGA revenue, as the case may be, and the difference would be deferred and either rebated or surcharged to customers, depending on the position of the deferral accounts, over a one-year period. The deferral balances would be reviewed annually by the UTC prior to the implementation of any rate adjustments under the mechanisms.

The proposed mechanisms would be subject to an annual earnings test which proposes that if our actual annual “Commission-basis” rate of return exceeds the most recently authorized Commission-basis rate of return for our Washington electric and natural gas operations, the amount of a proposed surcharge is reduced or eliminated to reduce the actual rate of return toward the Commission-authorized level. In addition, the mechanisms would be subject to an annual rate increase limitation which would prevent the amount of the incremental proposed rate adjustments under the mechanisms from exceeding a 3 percent rate increase for each of electric and natural gas operations.

The UTC has up to 11 months to review the filings and issue a decision.

Idaho General Rate Cases

A settlement agreement approved by the IPUC in September 2011 regarding electric and natural gas general rate cases filed in July 2011 provided for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, we are deferring certain changes in operation and maintenance costs related to the Coyote Springs 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. We compare actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defer the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Idaho were regulatory assets of $2.6 million as of March 31, 2014 and $2.8 million as of December 31, 2013.

In March 2013, the IPUC approved a settlement agreement in our electric and natural gas general rate cases filed in October 2012. As agreed to in the settlement, new rates were implemented in two phases: April 1, 2013 and October 1, 2013. Effective April 1, 2013, base rates increased for our Idaho natural gas customers by an overall 4.9 percent (designed to increase annual revenues by $3.1 million). There was no change in base electric rates on April 1, 2013. However, the settlement agreement provided for the recovery of the costs of the Palouse Wind Project through the PCA mechanism, subject to the 90 percent customers/10 percent Company sharing ratio, until these costs are reflected in base retail rates in our next general rate case.

The settlement also provided that, effective October 1, 2013, base rates increased for our Idaho natural gas customers by an overall 2.0 percent (designed to increase annual revenues by $1.3 million). A credit resulting from deferred natural gas costs of $1.6 million is being returned to our Idaho natural gas customers from October 1, 2013 through December 31, 2014, so the net annual average natural gas rate increase to natural gas customers effective October 1, 2013 was 0.3 percent.

Further, the settlement provided that, effective October 1, 2013, base rates increased for our Idaho electric customers by an overall 3.1 percent (designed to increase annual revenues by $7.8 million). A $3.9 million credit resulting from a payment made to us by the Bonneville Power Administration relating to its prior use of our transmission system is being returned to Idaho electric customers from October 1, 2013 through December 31, 2014, so the net annual average electric rate increase to electric customers effective October 1, 2013 was 1.9 percent.

The $1.6 million credit to Idaho natural gas customers and the $3.9 million credit to Idaho electric customers do not impact our net income.

The settlement agreement allows us to file a general rate case in Idaho in 2014; however, new rates resulting from the filing would not take effect prior to January 1, 2015. We are currently evaluating the need to file general rate cases in 2014 with proposed rates that would take effect on or after January 1, 2015. This provision does not preclude us from filing other rate adjustments such as the PGA.

The settlement agreement provides for an authorized return on equity of 9.8 percent and an equity ratio of 50.0 percent.

The settlement also includes an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent return on equity, we will refund to customers 50 percent of any earnings above the 9.8 percent. In 2013, our returns exceeded this level and we will refund $3.9 million to Idaho electric customers and $0.4 million to Idaho natural gas customers. Of the electric refund amount, $2.0 million was recorded in 2013 and $1.9 million was recorded in the first quarter of 2014 based on a revision of the allocation of costs between Idaho and Washington for regulatory purposes. The period over which these amounts will be returned to customers has not yet been determined by the IPUC.

Oregon General Rate Case

On January 21, 2014, the OPUC approved a settlement agreement to our natural gas general rate case (originally filed in August 2013). As agreed to in the settlement, new rates will be implemented in two phases: February 1, 2014 and November 1, 2014. Effective February 1, 2014, rates increased for Oregon natural gas customers on a billed basis by an overall 4.4 percent (designed to increase annual revenues by $4.3 million). Effective November 1, 2014, rates for Oregon natural gas customers will increase on a billed basis by an overall 1.6 percent (designed to increase annual revenues by $1.4 million).

The billed rate increase on November 1, 2014 could vary from that noted above as it is dependent upon the completion of our customer information system upgrade and the actual costs incurred through September 30, 2014, and the actual costs incurred through June 30, 2014 related to our Aldyl A distribution pipeline replacement program. The Oregon share of the estimated capital expenditures included in the general rate case settlement are $6.5 million and $2.0 million, respectively, for the two projects. If the actual costs incurred on the above projects are greater than the amounts contemplated in the general rate case settlement, the additional costs could be included in the November 1, 2014 rate adjustment, subject to a prudence review.

The approved settlement agreement provides for an overall authorized rate of return of 7.47 percent, with a common equity ratio of 48 percent and a 9.65 percent return on equity.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

In May 2013, the UTC approved our Petition for an order authorizing certain accounting and ratemaking treatment related to two issues. The first issue related to transmission revenues associated with a settlement between Avista Corp. and the Bonneville Power Administration (BPA), whereby BPA reimbursed the Company $11.7 million in the first quarter of 2013 for Bonneville's past use of our transmission system. The second issue related to $4.3 million of costs we incurred over the past several years for the development of a wind generation project site near Reardan, Washington, which has been terminated. The UTC authorized us to retain $7.6 million of the BPA settlement payment in 2013, representing the entire portion of the settlement allocable to our Washington business. However, this amount was deemed to first reimburse the Company for the $2.5 million of Reardan project costs that are allocable to our Washington business, leaving $5.1 million retained for the benefit of shareholders in 2013.

The BPA agreed to pay $3.2 million annually for the future use of our transmission system. We are separately tracking and deferring for the customers' benefit, the Washington portion of these revenue payments in 2013 and 2014 ($2.1 million annually). We implemented a one-year $4.2 million rate decrease for customers effective January 1, 2014 to partially offset our electric general rate increase effective January 1, 2014. To the extent actual revenues from the BPA in 2013 and 2014 differ from those refunded to customers in 2014, the difference will be added to or subtracted from the ERM balance. In Idaho, under the terms of the approved rate case settlement, 90 percent of the portion of the BPA settlement allocable to our Idaho business ($4.1 million) is being credited back to customers over 15 months, beginning October 2013, and we are amortizing the Idaho portion of Reardan costs ($1.7 million, including $1.3 million of incurred costs and $0.4 million of equity-related AFUDC) over a two-year period, beginning April 2013.

Purchased Gas Adjustments

PGAs are designed to pass through changes in natural gas costs to our customers with no change in gross 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 gas costs included in retail rates for supply that is not hedged. Total net deferred natural gas costs among all jurisdictions were a liability of $9.7 million as of March 31, 2014 and a liability of $12.1 million as of December 31, 2013.

The following PGAs went into effect in our various jurisdictions during 2013 and 2014:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	November 1, 2013	9.2%
Idaho	October 1, 2013	7.5%
Oregon	January 1, 2013 (1)	(0.8)%
	November 1, 2013	(7.9)%

(1) As it relates to the 2012 Oregon PGA, we requested that the PGA be implemented in two steps. The first step, implemented on November 1, 2012, was a decrease of 7.5 percent. The second step was an additional decrease of 0.8 percent, effective on January 1, 2013, to provide customers the net savings related to our purchase of the Klamath Falls Lateral transmission pipeline.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. Total net deferred power costs under the ERM were a liability of $15.8 million as of March 31, 2014, compared to a liability of $17.9 million as of December 31, 2013, and these deferred power cost balances represent amounts due to customers. As part of the approved Washington general rate case settlement in December 2012, during 2013 there was a one-year credit designed to return $4.4 million to electric customers from the ERM deferral balance to reduce the net average electric rate increase impact to customers in 2013. Additionally, during 2014 there is a one-year credit designed to return $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase impact to customers effective January 1, 2014 was also reduced. The credits to customers from the ERM balances do not impact our net income.

The difference in net power supply costs under the ERM primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level and availability of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices),
- the net value from optimization activities related to our generating resources, and
- retail loads.

Under the ERM, we absorb the cost or receive the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. We incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. We share annual power supply cost variances between $4.0 million and $10.0 million with customers. There is a 50 percent customers/50 percent Company sharing ratio when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. There is a 75 percent customers/25 percent Company sharing ratio when actual power supply expenses are lower (rebate to customers) than the amount included in base retail rates within this band. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, there is a 90 percent customers/10 percent Company sharing ratio of the cost variance.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
within +/- $0 to $4 million (deadband)	0%	100%
higher by $4 million to $10 million	50%	50%
lower by $4 million to $10 million	75%	25%
higher or lower by over $10 million	90%	10%

Under the ERM, we make an annual filing on or before April 1 of each year to provide the opportunity for the UTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. We made our annual filing on March 31, 2014 and as part of the UTC staff's review of this latest annual filing, the staff will review the prudence of the Colstrip outage from July 2013 through January 2014. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by UTC order.

We have a PCA mechanism in Idaho that 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 an asset of $8.8 million as of March 31, 2014 compared to an asset of $5.1 million as of December 31, 2013.

Results of Operations

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, Ecova and the other businesses) that follow this section.

Three months ended March 31, 2014 compared to the three months ended March 31, 2013

Utility revenues increased $6.0 million, after elimination of intracompany revenues of $34.9 million for the first quarter of 2014 and $41.4 million for the first quarter of 2013. Including intracompany revenues, electric revenues decreased $13.3 million and natural gas revenues increased $12.7 million. Retail electric revenues increased $10.0 million primarily due to general rate increases and a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers. Wholesale electric revenues decreased $2.8 million due to a decrease in sales volumes partially offset by an increase in sales prices while sales of fuel decreased $7.6 million. Other electric revenues decreased $11.0 million primarily due to the receipt of revenue from the BPA in 2013 for past use of our transmission system. Retail natural gas revenues increased $11.8 million due to higher rates (from PGAs and general rate increases) and an increase in volumes (due to colder weather), while wholesale natural gas revenues increased $0.8 million due to an increase in prices, partially offset by a decrease in volumes.

Ecova revenues increased $2.0 million to $44.4 million as a result of an increase in revenues associated with energy management services.

Utility resource costs decreased $9.1 million, after elimination of intracompany resource costs of $34.9 million for the first quarter of 2014 and $41.4 million for first quarter of 2013. Including intracompany resource costs, electric resource costs decreased $23.2 million and natural gas resource costs increased $7.5 million. The decrease in electric resource costs was primarily due to a decrease in power cost amortizations, other fuel costs (represents fuel that was purchased for generation but was later sold when conditions indicated that it was not economical to use the fuel for generation as part of the resource optimization process) and other regulatory amortizations. The increase in natural gas resource costs was primarily due to an increase in natural gas purchased, partially offset by a decrease in natural gas cost amortizations.

Utility other operating expenses increased $1.9 million and was the result of increased generation and distribution operating and maintenance expenses and increased transmission and general property maintenance expenses. These were partially offset by a decrease in pension and other post-retirement benefits expense.

Utility depreciation and amortization increased $2.8 million driven by additions to utility plant.

Utility taxes other than income taxes increased $2.3 million primarily due to increased state excise, municipal and property related taxes.

Ecova other operating expenses increased $1.9 million primarily reflecting increased costs associated with higher revenue volumes in energy management services.

Interest expense decreased $0.6 million primarily due to the long-term debt outstanding during the first quarter of 2014 having a lower interest rate than the long-term debt outstanding during the first quarter of 2013.

Income taxes increased $2.9 million and our effective tax rate was 36.5 percent for the first quarter of 2014 compared to 36.9 percent for the first quarter of 2013. The increase in expense was primarily due to an increase in income before income taxes.

Avista Utilities

Non-GAAP Financial Measures

The following discussion includes two financial measures that are considered “non-GAAP financial measures,” electric gross margin and natural gas gross margin. Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included (excluded) in the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of electric gross margin and natural gas gross margin is intended to supplement an understanding of Avista Utilities' operating performance. We use these measures to determine whether the appropriate amount of energy costs are being collected from our customers to allow for recovery of operating costs, as well as to analyze how changes in loads (due to weather, economic or other conditions), rates, supply costs and other factors impact our results of operations. These measures are not intended to replace income from operations as determined in accordance with GAAP as an indicator of operating performance. The calculations of electric and natural gas gross margins are presented below.

Three months ended March 31, 2014 compared to the three months ended March 31, 2013

Net income for Avista Utilities was $48.0 million for the first quarter of 2014, an increase from $42.3 million for the first quarter of 2013. Avista Utilities’ income from operations was $90.9 million for the first quarter of 2014, an increase from $82.8 million for the first quarter of 2013. The increase in net income and income from operations was primarily due to the implementation of general rate increases and colder weather, partially offset by expected increases in other operating expenses, depreciation and amortization, and taxes other than income taxes.

The following table presents our operating revenues, resource costs and resulting gross margin for the three months ended March 31 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
Operating revenues	$ 274,436	$ 287,738	$ 198,021	$ 185,271	$ (34,883)	$ (41,432)	$ 437,574	$ 431,577
Resource costs	121,880	145,063	133,500	125,999	(34,883)	(41,432)	220,497	229,630
Gross margin	$ 152,556	$ 142,675	$ 64,521	$ 59,272	$ —	$ —	$ 217,077	$ 201,947

Avista Utilities’ operating revenues increased $6.0 million and resource costs decreased $9.1 million, which resulted in an increase of $15.1 million in gross margin. The gross margin on electric sales increased $9.9 million and the gross margin on natural gas sales increased $5.2 million. The increase in electric gross margin was primarily due to general rate increases in Washington and Idaho, as well as weather that was colder than normal and colder than the prior year which increased heating loads. For the first quarter of 2014, we recognized a pre-tax benefit of $1.3 million under the ERM in Washington compared to a benefit of $3.1 million for the first quarter of 2013. The increase in natural gas gross margin was due to general rate increases and colder weather in our Washington and Idaho service territory, which increased heating loads. This was partially offset by warmer weather in our Oregon service territory.

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 reflected in the presentation of the separate results for electric and natural gas below.

The following table presents our utility electric operating revenues and megawatt-hour (MWh) sales for the three months ended March 31 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2014	2013	2014	2013
Residential	$ 106,803	$ 97,674	1,165	1,109
Commercial	73,916	69,366	787	756
Industrial	25,840	29,567	444	531
Public street and highway lighting	1,891	1,814	6	6
Total retail	208,450	198,421	2,402	2,402
Wholesale	37,290	40,094	976	1,149
Sales of fuel	24,150	31,772	—	—
Other	6,413	17,451	—	—
Provision for rate refunds	(1,867)	—	—	—
Total	$ 274,436	$ 287,738	3,378	3,551

Retail electric revenues increased $10.0 million primarily due to an increase in revenue per MWh (increased revenues $9.9 million) and partially due to an increase in total MWhs sold (increased revenues $0.1 million). The increase in revenue per MWh was primarily due to general rate increases and a change in revenue mix, with a greater percentage of retail revenue from residential and commercial customers.

The increase in total MWhs sold to residential customers was primarily the result of colder than normal weather. Compared to the first quarter of 2013, residential electric use per customer increased 4 percent and commercial use per customer increased 3 percent. Heating degree days at Spokane were 3 percent above historical average for the first quarter of 2014 and were 4 percent above the first quarter of 2013.

The decrease in total MWhs sold to industrial customers was primarily due to the expiration and replacement of a contract for one of our largest industrial customers, effective July 1, 2013. Under the new contract, we expect a decrease in revenues from annual power sales to this customer of approximately $21 million and a resulting decrease in resource costs of approximately $19 million. Any change in revenues and expenses associated with the new agreement, as compared with the revenues and expenses included in the last general rate case for this customer, will be tracked through the PCA in Idaho at 100 percent, until such time as the contract is included in the Company's base rates, so that we expect no impact on our gross margin or net income from the new agreement.

Wholesale electric revenues decreased $2.8 million due to a decrease in sales volumes (decreased revenues $6.6 million), partially offset by an increase in sales prices (increased revenues $3.8 million). The fluctuation in volumes and prices was primarily the result of our optimization activities during the quarter.

When current and forward electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the related natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel decreased $7.6 million due to a decrease in sales of natural gas fuel as part of thermal generation resource optimization activities, partially offset by an increase in natural gas prices. These thermal optimization transactions also include forward hedges using derivative instruments for electricity and natural gas. As relative power and natural gas prices vary, our volume of thermal optimization also varies. For the first quarter of 2014, $17.1 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. For the first quarter of 2013, $27.8 million of these sales were made to our natural gas operations.

Differences between revenues and costs from wholesale sales and sales of fuel are applied to reduce or increase resource costs as accounted for under the ERM, the PCA mechanism, and in general rate cases as part of base power supply costs.

Other electric revenues decreased $11.0 million primarily due to the receipt of $11.7 million of revenue from the BPA in the first quarter of 2013 for past use of our electric transmission system. The majority of this revenue was deferred as a regulatory liability and included in electric resource costs during the first quarter of 2013. During the second quarter of 2013, the UTC authorized us to retain a portion of this payment, which was then recognized to earnings, net of the Reardan wind generation project costs. See further information above at "Bonneville Power Administration Reimbursement and Reardan Wind Generation Project."

The 2013 Idaho general rate case settlement includes an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent return on equity, we will refund to customers 50 percent of any earnings above the 9.8 percent. In the first quarter of 2014, we revised our allocation of

2013 costs between Idaho and Washington for regulatory purposes, which resulted in an additional provision for rate refunds of $1.9 million to Idaho electric customers.

The following table presents our utility natural gas operating revenues and therms delivered for the three months ended March 31 (dollars and therms in thousands):

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2014	2013	2014	2013
Residential	$ 86,819	$ 79,954	86,161	84,140
Commercial	43,925	39,383	50,658	48,454
Interruptible	848	745	1,524	1,580
Industrial	1,396	1,134	1,851	1,676
Total retail	132,988	121,216	140,194	135,850
Wholesale	60,485	59,698	126,042	163,391
Transportation	2,154	2,082	47,010	46,286
Other	2,396	2,275	219	207
Provision for rate refunds	(2)	—	—	—
Total	$ 198,021	$ 185,271	313,465	345,734

Retail natural gas revenues increased $11.8 million due to higher retail rates (increased revenues $7.7 million) and an increase in volumes (increased revenues $4.1 million). Higher retail rates were due to PGAs, which passed through higher costs of natural gas, and general rate cases. We sold more retail natural gas in the first quarter of 2014 as compared to the first quarter of 2013 primarily due to colder weather in our Washington and Idaho service territory, partially offset by warmer weather in our Oregon service territory. Compared to the first quarter of 2013, residential natural gas use per customer increased 1 percent and commercial use per customer increased 4 percent. Heating degree days at Spokane were 3 percent above historical average for the first quarter of 2014, and 4 percent above the first quarter of 2013. Heating degree days at Medford were 13 percent below historical average for the first quarter of 2014 and 15 percent below the first quarter of 2013.

Wholesale natural gas revenues increased $0.8 million due to an increase in prices (increased revenues $18.7 million), partially offset by a decrease in volumes (decreased revenues $17.9 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, on nonpeak days we generally have more pipeline and storage capacity than what is needed for retail loads. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that partially offsets net natural gas costs. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. In the first quarter of 2014, $17.8 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In the first quarter of 2013, $13.6 million of these sales were made to our electric generation operations. 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.

The following table presents our average number of electric and natural gas retail customers for the three months ended March 31:

	Electric Customers		Natural Gas Customers	
	2014	2013	2014	2013
Residential	323,911	320,680	291,910	289,108
Commercial	40,689	40,096	34,144	34,074
Interruptible	—	—	35	39
Industrial	1,385	1,383	258	264
Public street and highway lighting	531	524	—	—
Total retail customers	366,516	362,683	326,347	323,485

The following table presents our utility resource costs for the three months ended March 31 (dollars in thousands):

	2014	2013
Electric resource costs:		
Power purchased	$ 61,665	$ 58,963
Power cost amortizations, net	(5,677)	(521)
Fuel for generation	34,967	36,174
Other fuel costs	20,210	30,697
Other regulatory amortizations, net	5,406	14,894
Other electric resource costs	5,309	4,856
Total electric resource costs	121,880	145,063
Natural gas resource costs:		
Natural gas purchased	132,868	119,903
Natural gas cost amortizations, net	(2,364)	3,120
Other regulatory amortizations, net	2,996	2,976
Total natural gas resource costs	133,500	125,999
Intracompany resource costs	(34,883)	(41,432)
Total resource costs	$ 220,497	$ 229,630

Power purchased increased $2.7 million due to an increase in wholesale prices (increased costs $4.9 million), partially offset by a decrease in the volume of power purchases (decreased costs $2.2 million). The fluctuation in volumes and prices was primarily the result of our overall optimization activities during the quarter.

Amortizations of net deferred power costs decreased electric resource costs by $5.7 million for the three months ended March 31, 2014 compared to a decrease of $0.5 million to electric resource costs for the three months ended March 31, 2013. During the three months ended March 31, 2014, we refunded to customers $1.3 million of previously deferred power costs in Idaho through the PCA rebate. We also refunded to Washington customers $2.2 million through an ERM rebate. During the three months ended March 31, 2014, actual power supply costs were below the amount included in base retail rates in Washington and within the $4 million deadband, as such, no regulatory asset or liability was recorded for these costs within the deadband. We deferred $2.3 million in Idaho for probable future surcharge to customers.

Fuel for generation decreased $1.2 million due to a decrease in natural gas generation, partially offset by an increase in natural gas fuel prices.

Other fuel costs decreased $10.5 million. This represents fuel and the related derivative instruments that were purchased for generation but were later sold when conditions indicated that it was not economical to use the fuel for generation, as part of the resource optimization process. When the fuel or related derivative instruments are sold, that revenue is included in sales of fuel.

Electric other regulatory amortizations decreased $9.5 million primarily due to the regulatory deferral of $7.6 million in the first quarter of 2013 for the Washington portion of the Bonneville revenue for past use of our transmission system pending approval from the UTC. We also deferred $3.9 million in the first quarter of 2013 for the Idaho portion of the Bonneville revenue for future refund to our Idaho customers. During the second quarter of 2013, the UTC authorized us to retain $7.6 million of the Bonneville revenue, which was then recognized to earnings, net of the Reardan wind generation project costs. See further information above at "Bonneville Power Administration Reimbursement and Reardan Wind Generation Project."

The expense for natural gas purchased increased $13.0 million due to an increase in the price of natural gas (increased costs $29.5 million), partially offset by a decrease in total therms purchased (decreased costs $16.5 million). Total therms purchased decreased due to a decrease in wholesale sales which are used to balance loads and resources as part of the natural gas procurement and resource optimization process, partially offset by an increase in retail sales. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs.

Ecova

Three months ended March 31, 2014 compared to the three months ended March 31, 2013

Ecova's net income attributable to Avista Corp. shareholders was $1.1 million for the three months ended March 31, 2014 compared to $1.2 million for the three months ended March 31, 2013. Operating revenues increased $2.0 million and total operating expenses increased $2.1 million. The increase in operating revenues was due to an increase in revenues from energy management services.

Ecova's other operating expenses associated with cost of services increased $2.1 million for the first quarter of 2014 and totaled $24.4 million. The increase was due to expenses associated with higher revenue volumes in energy management services.

Ecova's other operating expenses associated with selling, general and administrative expenses decreased by $0.2 million in the first quarter of 2014 and totaled $13.5 million. This decrease was related to a decrease in outside service expenses partially offset by an increase in business development expenses.

Depreciation and amortization increased $0.2 million due to additions to software development costs.

As of March 31, 2014, Ecova had over 700 expense management customers representing over 720,000 billed sites in North America. In the first quarter of 2014, Ecova managed bills totaling $5.6 billion, an increase of $0.5 billion as compared to the first quarter of 2013, which was due to an increase in the number of billed sites.

Other Businesses

Our other businesses include sheet metal fabrication, venture fund investments and real estate investments, as well as certain other operations of Avista Capital. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp., including AM&D, doing business as METALfx.

The following table shows our assets related to our other businesses as of March 31, 2014 and December 31, 2013 (dollars in thousands):

	March 31, 2014	December 31, 2013
Spokane Energy (1)	$ 39,814	$ 42,829
Avista Energy	12,416	12,399
METALfx	11,215	11,105
Steam Plant and Courtyard Office Center	6,981	7,055
Other	7,350	7,894
Total	$ 77,776	$ 81,282

(1) The decrease in the value of Spokane Energy assets represents the continued amortization of the long-term fixed rate electric capacity contract. See "Note 8 of the Notes to Condensed Consolidated Financial Statements" for further information regarding the long-term fixed rate electric capacity contract and the related nonrecourse long-term debt.

Three months ended March 31, 2014 compared to the three months ended March 31, 2013

The net loss from these operations was $0.6 million for the three months ended March 31, 2014 compared to a net loss of $1.1 million for the three months ended March 31, 2013. The net loss for the first quarter of 2014 was the result of $0.6 million (net of tax) of corporate costs, including costs associated with exploring strategic opportunities and litigation costs related to the previous operations of Avista Energy of $0.1 million (net of tax).

The losses above were partially offset by METALfx, which had net income of $0.1 million for the first quarter of 2014, compared to net income of $0.2 million for the first quarter of 2013.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on our consolidated financial statements and thus actual results could differ from the amounts reported and disclosed herein. Our critical accounting policies that require the use of estimates and assumptions were discussed in detail in the 2013 Form 10-K and have not changed materially from that discussion.

Liquidity and Capital Resources

Overall Liquidity

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

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

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

We periodically file for rate adjustments for recovery of operating costs and capital investments to seek the opportunity to earn returns as allowed by regulators. See further details in the section "Avista Utilities - Regulatory Matters."

For our utility operations, when power and natural gas costs exceed the levels currently recovered from retail customers, net cash flows are negatively affected. Factors that could cause purchased power and natural gas costs to exceed the levels currently recovered from our customers include, but are not limited to, higher prices in wholesale markets when we buy energy or an increased need to purchase power in the wholesale markets. Factors beyond our control that could result in an increased need to purchase power in the wholesale markets include, but are not limited to:

- increases in demand (due to either weather or customer growth),
- low availability of streamflows for hydroelectric generation,
- unplanned outages at generating facilities, and
- failure of third parties to deliver on energy or capacity contracts.

We monitor the potential liquidity impacts of changes to energy commodity prices and other increased operating costs for our utility operations. We believe that we have adequate liquidity to meet such potential needs through our $400.0 million committed line of credit.

As of March 31, 2014, we had $279.4 million of available liquidity under our committed line of credit. With our $400.0 million credit facility that expires in April 2019, we believe that we have adequate liquidity to meet our needs for the next 12 months.

Our utility has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, if prices rise above the level currently allowed in retail rates in periods when we are buying energy, deferral balances would increase, negatively affecting our cash flow and liquidity until such time as these costs, with interest, are recovered from customers.

Review of Cash Flow Statement

Overall During the three months ended March 31, 2014, positive cash flows from operating activities of $156.9 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $59.7 million, dividends of $19.2 million and the repayment of short-term borrowings of $60.0 million.

Operating Activities Net cash provided by operating activities was $156.9 million for the three months ended March 31, 2014 compared to $105.4 million for the three months ended March 31, 2013. Net cash provided by changes in certain current assets and liabilities was $75.2 million for the first quarter of 2014, compared to net cash provided of $25.2 million for the first quarter of 2013. The net cash provided by certain current assets and liabilities during the first quarter of 2014 primarily reflects positive cash flows related to accounts receivable, other current assets (primarily due to a decrease in cash collateral posted for energy commodity derivatives) and other current liabilities (primarily related to fluctuations in accrued taxes, accrued interest, and other miscellaneous accrued liabilities). These positive cash flows were partially offset by net cash outflows related to accounts payable.

The net cash provided by certain current assets and liabilities during the first quarter of 2013 primarily reflects positive cash flows from other current liabilities (primarily related to fluctuations in accrued taxes, accrued interest, and other miscellaneous accrued liabilities) and positive cash flows from a seasonal decrease in natural gas stored. These positive cash flows were partially offset by net cash outflows related to accounts payable and other current assets.

Net amortization of deferred power and natural gas costs decreased operating cash flows by $8.0 million for the three months ended March 31, 2014 compared to an increase in operating cash flows of $2.5 million for the three months ended March 31, 2013. The provision for deferred income taxes was $1.5 million for the three months ended March 31, 2014 compared to $1.1 million for the three months ended March 31, 2013. Contributions to our defined benefit pension plan were $11.0 million for the first quarter of 2014 and $14.7 million for the first quarter of 2013. Cash received for income taxes was $0.1 million for the first quarter of 2014, compared to cash paid of $1.3 million for the first quarter of 2013.

Investing Activities Net cash used in investing activities was $60.7 million for the three months ended March 31, 2014, a decrease compared to $86.7 million used for the three months ended March 31, 2013. Utility property capital expenditures decreased by $10.9 million for the first quarter of 2014 as compared to the first quarter of 2013. A significant portion of Ecova's funds held for clients are held as securities available for sale (with sales and maturities of $11.4 million for 2014, and purchases of $25.0 million and sales and maturities of $7.0 million for 2013).

Financing Activities Net cash used in financing activities was $88.6 million for the three months ended March 31, 2014 compared to net cash used of $5.0 million for the three months ended March 31, 2013. During the first quarter of 2014, short-term borrowings on Avista Corp.'s committed line of credit decreased $60.0 million. Net borrowings on Ecova's committed line of credit decreased $4.0 million during the period. Cash dividends paid increased to $19.2 million (or $0.3175 per share) for the first quarter of 2014 from $18.4 million (or $0.305 per share) for the first quarter of 2013. We issued $0.6 million of common stock during the three months ended March 31, 2014. Customer fund obligations at Ecova decreased $2.0 million.

During the three months ended March 31, 2013, short-term borrowings on Avista Corp.'s committed line of credit increased $0.5 million. There was no change in net borrowings on Ecova's line of credit with $3.0 million of borrowings and $3.0 million of repayments. We issued $1.1 million of common stock during the three months ended March 31, 2013. Customer fund obligations at Ecova increased $15.4 million.

Collateral Requirements

Our contracts for the purchase and sale of energy commodities can require collateral in the form of cash or letters of credit. As of March 31, 2014, we had deposited cash in the amount of $2.1 million and letters of credit of $2.5 million as collateral for certain energy derivative contracts. Price movements and/or a downgrade in our credit ratings could further impact the amount of collateral required. See "Credit Ratings" for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below "investment grade" based on our positions outstanding at March 31, 2014, we would potentially be required to post additional collateral of up to $18.6 million. This amount is different from the amount disclosed in "Note 5 of the Notes to Condensed Consolidated Financial Statements" because, while this analysis includes contracts that are not considered derivatives in addition to the contracts considered in Note 5, this analysis takes into account contractual threshold limits that are not considered in Note 5. Without contractual threshold limits, we would potentially be required to post additional collateral of $25.8 million.

Under the terms of interest rate swap agreements that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. This has not historically been significant to our liquidity position. As of March 31, 2014, we had interest rate swap agreements outstanding with a notional amount totaling $315 million and we had posted $2.2 million of cash collateral related to these outstanding agreements. If our credit ratings were lowered to below "investment grade" based on our interest rate swap agreements outstanding at March 31, 2014, we would be required to post additional collateral of $5.3 million.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of March 31, 2014 and December 31, 2013 (dollars in thousands):

	March 31, 2014		December 31, 2013	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 372	—%	$ 358	—%
Current portion of nonrecourse long-term debt (Spokane Energy)	13,872	0.5%	16,407	0.6%
Short-term borrowings	111,000	3.9%	171,000	6.0%
Long-term borrowings under committed line of credit	42,000	1.5%	46,000	1.6%
Long-term debt to affiliated trusts	51,547	1.8%	51,547	1.8%
Nonrecourse long-term debt (Spokane Energy)	—	—%	1,431	0.1%
Long-term debt	1,272,530	45.1%	1,272,425	44.5%
Total debt	1,491,321	52.8%	1,559,168	54.6%
Total Avista Corporation shareholders' equity	1,330,482	47.2%	1,298,266	45.4%
Total	$ 2,821,803	100.0%	$ 2,857,434	100.0%

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. Our shareholders' equity increased $32.2 million during the first quarter of 2014 primarily due to net income partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities, as well as issuances of long-term debt and common stock, are expected to be the primary source of funds for operating needs, dividends and capital expenditures for 2014. Borrowings under our $400.0 million committed line of credit will supplement these funds to the extent necessary.

We are party to two sales agency agreements for the sale from time to time of shares of our common stock; however, we do not plan to issue any shares under these agreements during 2014 due to the planned AERC transaction.

In the three months ended March 31, 2014, we issued $0.6 million (net of issuance costs) of common stock. The additional shares were issued under the dividend reinvestment and direct stock purchase plan, and employee plans.

We are planning to issue approximately $145.0 million of common stock in 2014 related to closing the planned acquisition of AERC.

We expect to issue approximately $190.0 million of long-term debt during 2014, including about $90.0 million of debt issuances combined between AERC or AEL&P associated with rebalancing the consolidated capital structure at AERC. This amount assumes we are going to refinance the existing net debt of AEL&P, estimated to be about $25.0 million at closing. The net debt outstanding at AEL&P does not include the Snettisham obligation which had a balance of $72.1 million as of December 31, 2013, as this relates to a power purchase commitment for which AEL&P has recorded a long-term power purchase asset and corresponding liability. In addition to rebalancing the consolidated capital structure at AERC, the proceeds from the issuance of long-term debt will be used to repay a portion of short-term borrowings, fund utility capital expenditures and other contractual commitments at Avista Corp.

Included in our 2014 liquidity estimates is approximately $50.0 million in lower tax payments due to the planned adoption of federal tax tangible property regulations. This will be accomplished through an accounting method change filing with the Internal Revenue Service that will retroactively modify which tangible property transactions we expense versus capitalize and depreciate for federal tax purposes.

We have a committed line of credit with various financial institutions in the total amount of $400 million. In April 2014, we amended this committed line of credit agreement to extend the expiration date to April 2019. The amendment also provides us with the option to request an extension for an additional one or two years beyond April 2019, provided there is no event of default prior to the requested extension and the requested extension does not cause the remaining term until the expiration date to exceed five years. The amendment did not change the amount of the committed line of credit. Borrowings under this line of credit agreement are classified as short-term on the Condensed Consolidated Balance Sheets.

This facility contains customary covenants and default provisions, including 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 March 31, 2014, we were in compliance with this covenant with a ratio of 52.8 percent.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under our committed line of credit were as follows as of and for the three months ended March 31 (dollars in thousands):

	2014	2013
Borrowings outstanding at end of period	$ 111,000	$ 52,500
Letters of credit outstanding at end of period	$ 9,614	$ 12,608
Maximum borrowings outstanding during the period	$ 171,000	$ 52,500
Average borrowings outstanding during the period	$ 90,806	$ 16,619
Average interest rate on borrowings during the period	0.96%	1.09%
Average interest rate on borrowings at end of period	0.93%	1.17%

As part of our cash management practices and operations, Ecova and Avista Corp. entered into an arrangement in January 2012 under which (1) Avista Corp. issued to Ecova a master unsecured promissory note and (2) Ecova will from time to time make short-term loans to Avista Corp. as a temporary investment of its funds received from its clients. The master promissory note limits the total outstanding indebtedness to no more than $50.0 million in principal. Additionally, such loans are required to be repaid on the last business day of each quarter (March, June, September and December) and sooner upon demand by Ecova. Amounts are loaned at a rate consistent with Avista Corp.'s credit facility. The average balance outstanding was $37.9 million and the maximum balance was $50.0 million during the three months ended March 31, 2014. The average balance outstanding was $32.1 million and the maximum balance was $50.0 million during the three months ended March 31, 2013.

Any default on the line of credit or other financing arrangements of Avista Corp. or any of our "significant subsidiaries," if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. Avista Corp. does not guarantee the indebtedness of any of its subsidiaries. As of March 31, 2014, 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 the "Ecova Credit Agreement" section below for further information regarding Ecova's committed line of credit.

Avista Utilities Capital Expenditures

We expect utility capital expenditures to be about $335 million for 2014, $355 million for 2015, and $350 million for 2016. Most of these capital expenditures are for upgrading and maintenance of our existing facilities, and not for construction of new facilities and we expect all of these capital expenditures to be included in rate base in future years. These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

Future generation resource decisions may be further impacted by legislation for restrictions on greenhouse gas (GHG) emissions and renewable energy requirements as discussed at "Environmental Issues and Other Contingencies."

Included in our estimates of capital expenditures is the replacement of our customer information and work management systems, which is expected to be completed by the end of 2014. Our customer information and work management systems are two of our most critical technology systems and are interconnected to many other systems in our company. We expect to spend approximately $80.0 million (including internal labor) over the term of the project. As of March 31, 2014 we have spent $56.6 million on the project (including internal labor).

Ecova Credit Agreement

Ecova has a $125.0 million committed line of credit agreement with various financial institutions that has an expiration date of July 2017. The credit agreement is secured by all of Ecova's assets excluding investments and funds held for clients. There were $42.0 million of long-term borrowings outstanding under Ecova's credit agreement as of March 31, 2014.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant which requires that Ecova's "Consolidated Total Funded Debt to EBITDA Ratio" (as defined in the credit agreement) must be 2.50 to 1.00 or less, with provisions in the credit agreement allowing for a temporary increase of this ratio if a qualified acquisition is consummated by Ecova. In addition, Ecova's "Consolidated Fixed Charge Coverage Ratio" (as defined in the credit agreement) must be greater than 1.50 to 1.00 as of the last day of any fiscal quarter. As of March 31, 2014, Ecova was in compliance with these covenants and based on the Consolidated Total Funded Debt to EBITDA Ratio, Ecova could borrow an additional $38.8 million and still be compliant with the covenants. The covenant restrictions are calculated on a rolling twelve month basis, so this additional borrowing capacity could increase or decrease or Ecova could be required to pay down the outstanding debt as future results change.

Ecova Redeemable Stock

Ecova's amended employee stock incentive plan provides an annual window at which time certain holders of common stock can put their shares back to Ecova, providing the shares are held for a minimum of six months and a day. Stock is reacquired at fair market value at the date of reacquisition. The value of the redeemable noncontrolling interests in Ecova associated with redeemable stock options and other outstanding redeemable stock was $16.0 million at March 31, 2014, a slight increase from $15.9 million at December 31, 2013. Options are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price). In 2009, the Ecova employee stock incentive plan was amended such that, on a prospective basis, not all options granted under the plan have the put right.

Off-Balance Sheet Arrangements

As of March 31, 2014, we had $9.6 million in letters of credit outstanding under our $400.0 million committed line of credit, compared to $27.4 million as of December 31, 2013.

Pension Plan

In the three months ended March 31, 2014 we contributed $11.0 million to the pension plan. We expect to contribute a total of $80.0 million to the pension plan in the period 2014 through 2018, with the following contributions.

	2014	2015	2016	2017	2018	Total
Pension Plan Funding	$ 32,000	$ 20,000	$ 10,000	$ 9,000	$ 9,000	$ 80,000

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 of the above variables.

In October 2013, we revised our defined benefit pension plan such that as of January 1, 2014 the plan is closed to all non-union employees hired or rehired by us on or after January 1, 2014. All actively employed non-union employees that were hired prior to January 1, 2014 and are currently covered under the defined benefit pension plan will continue accruing benefits as originally specified in the plan. A defined contribution 401(k) plan will replace the defined benefit pension plan for all non-union employees hired or rehired on or after January 1, 2014. Under the defined contribution plan we will provide a non-elective contribution as a percentage of each employee's pay based on his or her age. This defined contribution is in addition to the existing 401(k) contribution in which we match a portion of the pay deferred by each participant. In addition to the above changes, we also revised our lump sum calculation for non-union retirees under the defined benefit pension plan to provide non-union participants who retire on or after January 1, 2014 with a lump sum amount equivalent to the present value of the annuity based upon applicable discount rates.

Also in October 2013, we revised the health care benefit plan such that beginning on January 1, 2020, the method for calculating health insurance premiums for non-union retirees under age 65 and active Company employees will be revised. The revisions will result in separate health insurance premium calculations for each group. In addition, for non-union employees hired or rehired on or after January 1, 2014, upon retirement we will no longer provide a contribution towards his or her medical premiums. We will provide access to our retiree medical plan, but the non-union employees hired or rehired on or after January 1, 2014 will pay the full cost of premiums upon retirement.

In April 2014, the local union in Oregon for the International Brotherhood of Electrical Workers accepted the defined benefit pension and health care benefit plan changes above in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014.

Credit Ratings

Our access to capital markets and our cost of capital are directly affected by our credit ratings. In addition, many of our contracts for the purchase and sale of energy commodities contain terms dependent upon our credit ratings. See “Collateral Requirements” and “Note 5 of the Notes to Condensed Consolidated Financial Statements.”

The following table summarizes our credit ratings as of May 7, 2014:

	Standard & Poor’s (1)	Moody’s (2)
Corporate/Issuer rating	BBB	Baa1
Senior secured debt	A-	A2
Senior unsecured debt	BBB	Baa1

(1) Standard & Poor’s lowest “investment grade” credit rating is BBB-.
(2) Moody’s lowest “investment grade” credit rating is Baa3.

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

Dividends

The Board of Directors considers the level of dividends on our common stock on a regular basis, taking into account numerous factors including, without limitation:

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

Our net income available for dividends is primarily derived from our regulated utility operations.

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

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements (see Item 7. Management's Discussion and Analysis - "Capital Resources" for compliance with these covenants), and
- the hydroelectric licensing requirements of section 10(d) of the FPA (see "Note 1 of Notes to Condensed Consolidated Financial Statements").

On February 7, 2014, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.3175 per share on the Company's common stock. This was an increase of $0.0125 per share, or 4 percent from the previous quarterly dividend of $0.305 per share.

Contractual Obligations

Our future contractual obligations have not materially changed during the three months ended March 31, 2014. See the 2013 Form 10-K.

Economic Conditions

The general economic data, on both national and local levels, contained in this section is based, in part, on independent government and industry publications, reports by market research firms or other independent sources. While we believe that these publications and other sources are reliable, we have not independently verified such data and can make no representation as to its accuracy.

We track multiple economic indicators affecting three distinct metropolitan areas in our service area: Spokane, Washington, Coeur d'Alene, Idaho, and Medford, Oregon. Several key indicators are employment change, unemployment rates and foreclosure rates. On a year-over-year basis, March 2014 showed positive job growth, and lower unemployment rates in all three metropolitan areas. Foreclosure rates are in line with or below the U.S. rate in all three areas. However, except for Coeur d'Alene, the unemployment rates are still above the national average and two key leading indicators, initial unemployment claims and residential building permits, continue to signal modest growth over the next 12 months. Therefore, for the rest of 2014, we continue to expect economic growth in our service area to be somewhat slower than the U.S. as a whole.

Seasonally adjusted nonfarm employment in our eastern Washington, northern Idaho, and southwestern Oregon metropolitan service areas exhibited moderate growth between March 2013 and March 2014. In Spokane, Washington employment growth was 0.9 percent with gains in mining, logging, and construction; trade, transportation, and utilities; financial activities; other services; and government. Employment increased by 1.3 percent in Coeur d'Alene, Idaho, reflecting gains in construction; manufacturing; trade, transport, and utilities; information; and government. In Medford, Oregon, employment growth was 0.1 percent, with gains in manufacturing; financial activities; and government offset by declines in construction; information; and professional and business services. U.S. nonfarm sector jobs grew by 1.7 percent in the same twelve-month period.

Seasonally adjusted unemployment rates went down in March 2014 from the year earlier in Spokane, Coeur d'Alene, and Medford. In Spokane the rate was 8.2 percent in March 2013 and declined to 7.2 percent in March 2014; in Coeur d'Alene the rate went from 7.6 percent to 5.9 percent; and in Medford the rate declined from 9.7 percent to 8.6 percent. The U.S. rate declined from 7.5 percent to 6.7 percent in the same period.

The housing market in our service area continues to experience foreclosure rates in line with or lower than the national average. The March 2014 national rate was 0.09 percent, compared to 0.09 percent in Spokane County, Washington; 0.01 percent in Kootenai County (Coeur d'Alene), Idaho; and 0.01 percent in Jackson County (Medford), Oregon.

Environmental Issues and Contingencies

Our environmental issues and contingencies disclosures have not materially changed except for the following during the three months ended March 31, 2014. See the 2013 Form 10-K.

Climate Change - Federal Regulatory Actions

The U.S. Supreme Court ruled in 2007 that the EPA had authority under the CAA to regulate greenhouse gas emissions from new motor vehicles; subsequently, the EPA issued regulations on tailpipe emissions of greenhouse gases (GHG). When these regulations became effective, GHG became regulated pollutants under the Prevention of Significant Deterioration (PSD) preconstruction permit program and the Title V operating permit program, which both apply to power plants and other commercial and industrial facilities. In 2010, the EPA issued a final rule, known as the Tailoring Rule, governing how these programs would be applied to stationary sources, including power plants. The EPA re-proposed the rule in late 2013 setting performance standards for GHG emissions from *new and modified* fossil fuel-fired electric generating units and announced plans to issue GHG emissions guidelines for *existing* sources. The rule for *new* sources has not been finalized, and the proposed rule for *existing* sources is expected in June 2014.

Climate Change - State Legislation and State Regulatory Activities

On April 29, 2014, Washington State Governor Jay Inslee issued Executive Order 14-04, "Washington Carbon Pollution Reduction and Clean Energy Action." The order creates a "Climate Emissions Reduction Task Force" to provide recommendations to the Governor on design and implementation of a market-based carbon pollution program to inform possible legislative proposals in 2015. The order calls on the program to "establish a cap on carbon pollution emissions, with binding requirements to meet our statutory emission limits." The order also states that the Governor's Legislative Affairs and Policy Office "will seek negotiated agreements with key utilities and others to reduce and eliminate over time the use of electrical power produced from coal." While we cannot predict the outcome of actions arising out of the Governor's executive order, we will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to the continued operation of cost-effective generation assets.

In 2013, the Oregon Legislature enacted Senate Bill 306, directing the Legislative Revenue Office to examine the feasibility of imposing a carbon tax on a statewide basis. A final report will be submitted to the Legislature by November 15, 2014. The scope of the study includes an assessment of "potential methods for the [tax] treatment of imported and exported energy sources," which could entail the taxation of natural gas used to generate electricity and/or of the carbon content attributed to electricity produced in the state. A proposal to tax natural gas as a fuel for electricity generation and to tax the carbon content of electricity produced in, but exported from, Oregon could have implications for the cost of operating Coyote Springs II. We will monitor the development of the study and any attendant recommendations made therein, but we cannot predict any actual material impact at this time.

Kettle Falls Generation Station - Diesel Spill Investigation and Remediation

On December 24, 2013, our operations staff at the Kettle Falls Generation Station discovered that approximately 10,000 gallons of diesel fuel had leaked underground from the piping system used to fuel heavy equipment. We made all proper agency notifications and worked closely with the Washington State Department of Ecology during the spill response and investigation phase. We installed down gradient monitoring wells. There is no indication that ground or surface water is threatened by the spill. We plan to implement a voluntary cleanup action, and a request for proposal is being developed for the most effective remediation system. See "Note 11 of the Notes to Condensed Consolidated Financial Statements" for further discussion of this issue.

Other

For other environmental issues and other contingencies see "Note 11 of the Notes to Condensed Consolidated Financial Statements."

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our primary market risk exposures are:

- Commodity prices for electric power and natural gas
- Credit related to the wholesale energy market
- Interest rates on long-term and short-term debt
- Foreign exchange rates between the U.S. dollar and the Canadian dollar

Commodity Price Risk

Our qualitative commodity price risk disclosures have not materially changed during the three months ended March 31, 2014. Please refer to the 2013 Form 10-K. The following table presents energy commodity derivative fair values as a net asset or (liability) as of March 31, 2014 that are expected to be delivered in each respective year (dollars in thousands):

	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)
2014	$ 326	$ 2,109	$ 218	$ 23,310	$ 805	$ 2,778	$ (897)	$ (16,672)
2015	(2,001)	(208)	(52)	2,130	(22)	1,205	(1,201)	(405)
2016	(3,153)	595	(485)	(1,845)	(57)	3,406	(724)	144
2017	(3,005)	—	126	—	(98)	—	—	—
2018	(2,866)	—	—	—	(162)	—	—	—
Thereafter	(1,592)	—	—	—	(83)	—	—	—

The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2013 that are expected to be delivered in each respective year (dollars in thousands):

	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)
2013	$ (215)	$ 7,243	$ (6,131)	$ (2,663)	$ (221)	$ (6,226)	$ (1,214)	$ (1,404)
2014	(2,818)	(1,798)	(2,450)	(9,586)	(34)	3,121	—	4,298
2015	(3,289)	—	(1,171)	(7,400)	(83)	3,529	—	2,230
2016	(2,955)	—	(86)	—	(187)	—	—	—
2017	(2,661)	—	—	—	(313)	—	—	—
Thereafter	(1,456)	—	—	—	(148)	—	—	—

(1) Physical transactions represent commodity transactions where we will take or make delivery of either electricity or natural gas and financial transactions represent derivative instruments with no physical delivery, such as futures, swaps, 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 delivered and will be included in the various 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.

Credit Risk

Our credit risk has not materially changed during the three months ended March 31, 2014. See the 2013 Form 10-K.

Risk Management for Energy Resources

We use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have an energy resources risk policy, which includes our wholesale energy markets credit policy and control procedures to manage these risks, both qualitative and quantitative. The 2013 Form 10-K contains a discussion of risk management policies and procedures.

Interest Rate Risk

Our qualitative interest rate risk disclosures have not materially changed during the three months ended March 31, 2014. See the 2013 Form 10-K.

As of March 31, 2014, we had interest rate swap agreements with a total notional amount of $315.0 million with mandatory cash settlement dates of 2014 through 2018. In anticipation of issuing long-term debt in future years, we entered into three interest rate swap agreements in April 2014, with a total notional amount of $50.0 million and mandatory cash settlement dates ranging from 2015 to 2018.

As of March 31, 2014, we had a short-term derivative asset of $10.6 million, a long-term derivative asset of $7.5 million and a long-term derivative liability of $6.7 million, with offsetting regulatory liabilities and a regulatory asset, respectively on the

Condensed Consolidated Balance Sheets in accordance with regulatory accounting practices. The long-term derivative liability of $6.7 million reflects the offsetting of $2.2 million of cash collateral against the net derivative positions where a legal right of offset exists.

As of December 31, 2013, we had interest rate swap agreements with a total notional amount of $245.0 million and current derivative asset of $14.0 million and a long-term derivative asset of $19.6 million with an offsetting regulatory liability on the Condensed Consolidated Balance Sheets in accordance with regulatory accounting practices.

Foreign Currency Risk

Our qualitative foreign currency risk disclosures have not materially changed during the three months ended March 31, 2014. See the 2013 Form 10-K. As of March 31, 2014, we had a current derivative asset for foreign currency hedges of less than $0.1 million included in other current assets on the Condensed Consolidated Balance Sheet. As of March 31, 2014, we had entered into 23 Canadian currency forward contracts with a notional amount of $13.1 million ($14.6 million Canadian). As of December 31, 2013, we had entered into 23 Canadian currency forward contracts with a notional amount of $8.6 million ($9.2 million Canadian) and had a current derivative asset of less than $0.1 million.

Further information for derivatives and fair values is disclosed at “Note 5 of the Notes to Condensed Consolidated Financial Statements” and “Note 9 of the Notes to Condensed Consolidated Financial Statements.”

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) 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. Under the supervision and with the participation of the Company’s management, including the Company’s principal executive officer and principal financial officer, the Company 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. Disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon the Company’s 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 March 31, 2014.

There have been no changes in the Company's internal control over financial reporting that occurred during the first quarter of 2014 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 11 of Notes to Condensed Consolidated Financial Statements” in “Part I. Financial Information Item 1. Condensed Consolidated Financial Statements.”

Item 1A. Risk Factors

Please refer to the 2013 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 Securities and Exchange Commission (including this Quarterly Report on Form 10-Q), and elsewhere. These risk factors have not materially changed from the disclosures provided in the 2013 Form 10-K. In addition to these risk factors, see also “Forward-Looking Statements” for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

Item 4. Mine Safety Disclosures

Not applicable.

Item 6. Exhibits

12	Computation of ratio of earnings to fixed charges*
15	Letter Re: Unaudited Interim Financial Information*
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)*
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)*
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)**
101	The following financial information from the Quarterly Report on Form 10−Q for the period ended March 31, 2014, formatted in XBRL (Extensible Business Reporting Language) and filed electronically herewith: (i) the Condensed Consolidated Statements of Income; (ii) Condensed Consolidated Statements of Comprehensive Income; (iii) the Condensed Consolidated Balance Sheets; (iv) the Condensed Consolidated Statements of Cash Flows; (v) the Condensed Consolidated Statements of Equity and Redeemable Noncontrolling Interests; and (vi) the Notes to Condensed Consolidated Financial Statements.*

*	Filed herewith.
**	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: May 7, 2014

/s/ Mark T. Thies
Mark T. Thies
Senior Vice President,
Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Exhibit 12

AVISTA CORPORATION

Computation of Ratio of Earnings to Fixed Charges
Consolidated
(Thousands of Dollars)

	Three months ended March 31, 2014	Years Ended December 31 2013	2012	2011	2010	2009
Fixed charges, as defined:						
Interest charges	$ 18,242	$ 75,409	$ 73,633	$ 69,591	$ 72,010	$ 61,361
Amortization of debt expense and premium - net	953	3,813	3,803	4,617	4,414	5,673
Interest portion of rentals	636	2,762	2,717	2,154	2,027	1,874
Total fixed charges	$ 19,831	$ 81,984	$ 80,153	$ 76,362	$ 78,451	$ 68,908
Earnings, as defined:						
Pre-tax income from continuing operations	$ 77,157	$ 175,524	$ 120,061	$ 160,171	$ 146,105	$ 134,971
Add (deduct):						
Capitalized interest	(661)	(3,676)	(2,401)	(2,942)	(298)	(545)
Total fixed charges above	19,831	81,984	80,153	76,362	78,451	68,908
Total earnings	$ 96,327	$ 253,832	$ 197,813	$ 233,591	$ 224,258	$ 203,334
Ratio of earnings to fixed charges	4.86	3.10	2.47	3.06	2.86	2.95

Exhibit 15

May 7, 2014

Avista Corporation
Spokane, Washington

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited interim financial information of Avista Corporation and subsidiaries for the periods ended March 31, 2014 and 2013, as indicated in our report dated May 7, 2014; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, is incorporated by reference in Registration Statement Nos. 2-81697, 2-94816, 033-54791, 333-03601, 333-22373, 333-33790, 333-47290, 333-126577, and 333-179042 on Form S-8; in Registration Statement Nos. 333 -187306 and 333-177981 on Form S-3; and in Registration Statement No 333-194310 on Form S-4 filed on March 4, 2014.

We are also aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statements prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Seattle, Washington

Exhibit 31.1

CERTIFICATION

I, Scott L. Morris, 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: May 7, 2014

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, Mark T. Thies, 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: May 7, 2014

/s/ Mark T. Thies

Mark T. Thies
Senior Vice President,
Chief Financial Officer, and Treasurer
(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, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the “Company”), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 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: May 7, 2014

/s/ Scott L. Morris

Scott L. Morris
Chairman of the Board, President
and Chief Executive Officer

/s/ Mark T. Thies

Mark T. Thies
Senior Vice President,
Chief Financial Officer, and Treasurer