AVISTA CORP
Form 10-K
February 25, 2015

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

Form 10-K
(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED December 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

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

Title of Class	Name of Each Exchange on Which Registered
Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
Title of Class
Preferred Stock, Cumulative, Without Par Value

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

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

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 x 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 x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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 x	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 x

The aggregate market value of the Registrant's outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $2,018,577,718 based on the last reported sale price thereof on the consolidated tape on June 30, 2014.

As of January 31, 2015, 62,344,484 shares of Registrant's Common Stock, no par value (the only class of common stock), were outstanding.

Documents Incorporated By Reference

Document	Part of Form 10-K into Which Document is Incorporated
Proxy Statement to be filed in connection with the annual meeting of shareholders to be held on May 7, 2015. Prior to such filing, the Proxy Statement filed in connection with the annual meeting of shareholders held on May 8, 2014.	Part III, Items 10, 11, 12, 13 and 14

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* = not an applicable item in the 2014 calendar year for Avista Corp.

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AVISTA CORPORATION

ACRONYMS AND TERMS

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

Acronym/Term		Meaning
aMW	-	Average Megawatt - a measure of the average rate at which a particular generating source produces energy over a period of time
AEL&P	-	Alaska Electric Light and Power Company, the primary operating subsidiary of AERC
AERC	-	Alaska Energy and Resources Company, a privately-held company based in Juneau, Alaska. The Company entered into an agreement and plan of merger with AERC on November 4, 2013 and the acquisition was completed on July 1, 2014.
AFUDC	-	Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
AM&D	-	Advanced Manufacturing and Development, does business as METALfx
ASC	-	Accounting Standards Codification
Avista Capital	-	Parent company to the Company's non-utility businesses
Avista Corp.	-	Avista Corporation, the Company
Avista Energy	-	Avista Energy, Inc., an electricity and natural gas marketing, trading and resource management business, subsidiary of Avista Capital. This entity is currently inactive; however, we still incur legal fees associated with this entity.
Avista Utilities	-	Operating division of Avista Corp. (not a subsidiary) comprising the regulated utility operations
BPA	-	Bonneville Power Administration
Capacity	-	The rate at which a particular generating source is capable of producing energy, measured in KW or MW
Cabinet Gorge	-	The Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
Colstrip	-	The coal-fired Colstrip Generating Plant in southeastern Montana
Coyote Springs 2	-	The natural gas-fired combined-cycle Coyote Springs 2 Generating Plant located near Boardman, Oregon
CT	-	Combustion turbine
Deadband or ERM deadband	-	The first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the ERM in the state of Washington
Dekatherm	-	Unit of measurement for natural gas; a dekatherm is equal to approximately one thousand cubic feet (volume) or 1,000,000 BTUs (energy)
Ecology	-	The state of Washington's Department of Ecology
Ecova	-	Ecova, Inc., a provider of facility information and cost management services for multi-site customers and energy efficiency program management for commercial enterprises and utilities throughout North America, subsidiary of Avista Capital. Ecova was sold on June 30, 2014.
Energy	-	The amount of electricity produced or consumed over a period of time, measured in KWH or MWH. Also, refers to natural gas consumed and is measured in dekatherms.
EPA	-	Environmental Protection Agency
ERM	-	The Energy Recovery Mechanism, a mechanism for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Washington
FASB	-	Financial Accounting Standards Board
FERC	-	Federal Energy Regulatory Commission

GAAP	-	Generally Accepted Accounting Principles
GHG	-	Greenhouse gas
GS	-	Generating station
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
Jackson Prairie	-	Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington

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Juneau	-	The City and Borough of Juneau, Alaska
kV	-	Kilovolt (1000 volts): a measure of capacity on transmission lines
KW, KWH	-	Kilowatt (1000 watts): a measure of generating output or capability. Kilowatt-hour (1000 watt hours): a measure of energy produced.
Lancaster Plant	-	A natural gas-fired combined cycle combustion turbine plant located in Idaho
MPSC	-	Public Service Commission of the State of Montana
MW, MWH	-	Megawatt: 1000 KW. Megawatt-hour: 1000 KWH.
NERC	-	North American Electricity Reliability Corporation
Noxon Rapids	-	The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OPUC	-	The Public Utility Commission of Oregon
PCA	-	The Power Cost Adjustment mechanism, a procedure for accounting and rate recovery of certain power supply costs accepted by the utility commission in the state of Idaho
PGA	-	Purchased Gas Adjustment
PLP	-	Potentially liable party
PUD	-	Public Utility District
PURPA	-	The Public Utility Regulatory Policies Act of 1978, as amended
RCA	-	The Regulatory Commission of Alaska
RTO	-	Regional Transmission Organization
Salix LNG	-	Salix, Inc., a subsidiary of Avista Capital, specializing in small scale liquified natural gas projects, primarily in Western North America.
Spokane Energy	-	Spokane Energy, LLC, a special purpose limited liability company and all of its membership capital is owned by Avista Corp.
Spokane River Project	-	The five hydroelectric plants operating under one FERC license on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls)
Therm	-	Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
UTC	-	Washington Utilities and Transportation Commission
Watt	-	Unit of measurement for electricity; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt

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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 have underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Annual Report on Form 10-K), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those 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 exp

Forward-looking statements (including those made in this Annual Report on Form 10-K) are subject to a variety of risks and 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;
- volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, 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;
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the outcome of pending legal proceedings arising out of the “western energy crisis” of 2000 and 2001, specifically related to the Pacific Northwest refund proceedings;

- the outcome of legal proceedings and other contingencies;

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- 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 decline 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, avalanches 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 our utilities' service area 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;

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- 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;
- 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;
- compliance with extensive federal, state and local legislation and regulation, including numerous environmental, health, safety and other laws and regulations that affect our operations and costs;
- our ability to fully collect the indemnification escrow amounts because of information that was covered under management's representations and warranties related to the Ecova sale which could be inaccurate or incomplete at the time of sale, or because of new information which could be identified subsequent to the sale date, and
- adverse impacts to our Alaska operations because a majority of the hydroelectric power generation for such operations is provided by a single facility that is subject to a long-term power purchase agreement; hence any issues that negatively affect this facility's ability to generate or transmit power, the cost and ability to replace power in the event of an extended outage, any decrease in the demand for the power generated by this facility or any loss by our subsidiary of its contractual rights with respect thereto or other adverse effect thereon could negatively affect our Alaska operations' financial results.

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.

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AVISTA CORPORATION

PART I

ITEM 1. BUSINESS

COMPANY OVERVIEW

Avista Corporation (Avista Corp. or the Company), incorporated in the territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. As of December 31, 2014, we employed 1,658 people in our primary utility operations (Avista Utilities) and 216 people in our subsidiary businesses. Our corporate headquarters are in Spokane, Washington, the second-largest city in Washington. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region (eastern Washington and northern Idaho). Regional services include government and higher education, medical services, retail trade and finance. The Inland Northwest also coincides closely with our utility service area in Washington and Idaho. Our natural gas utility operations also include separate service areas in parts of Oregon. Through our subsidiary Alaska Electric Light and Power Company, we also provide electric services in the City and Borough of Juneau (Juneau), Alaska.

As of December 31, 2014, we have two reportable business segments as follows:

- Avista Utilities – an operating division of Avista Corp. (not a subsidiary) that comprises our regulated utility operations in the Pacific Northwest. 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. We also supply electricity to a small number of customers in Montana, most of whom are employees who operate our Noxon Rapids generating facility. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas.
- Alaska Electric Light and Power Company - the primary operating subsidiary of Alaska Energy and Resources Company (AERC), which provides electric services in the City and Borough of Juneau, Alaska. We completed our acquisition of AERC on July 1, 2014, and as of that date, AERC is a wholly-owned subsidiary of Avista Corp. See "Note 4 of the Notes to Consolidated Financial Statements" for further discussion regarding this acquisition.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, as well as certain other investments of Avista Capital, Inc. (Avista Capital), which is a direct, wholly owned subsidiary of Avista Corp. In addition, as of July 1, 2014 we own AERC and AJT Mining Properties, Inc. (AJT Mining), which is a wholly-owned subsidiary of AERC and is an inactive mining company holding certain properties. 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.

Total Avista Corp. shareholders' equity was $1,483.7 million as of December 31, 2014, of which $57.3 million represented our investment in Avista Capital and $91.0 million represented our investment in AERC.

During the first half of 2014, Avista Capital's subsidiaries included Ecova, Inc. (Ecova), which was an 80.2 percent owned subsidiary prior to its disposition on June 30, 2014. Ecova was 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 "Item 6. Selected Financial Data" and "Note 23 of the Notes to Consolidated Financial Statements" for information with respect to the operating performance of each business segment (and other subsidiaries). See "Note 5 of the Notes to Consolidated Financial Statements" for information regarding the disposition of Ecova.

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AVISTA UTILITIES

General

Through our Avista Utilities operating division, we generate, transmit and distribute electricity and distribute natural gas in the Pacific Northwest. Retail electric and natural gas customers include residential, commercial and industrial classifications. We also engage in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and our load-serving obligation.

Avista Utilities provides electric distribution and transmission, as well as natural gas distribution, services in parts of eastern Washington and northern Idaho. We also provide natural gas distribution service in parts of northeastern and southwestern Oregon. At the end of 2014, we supplied retail electric service to 370,000 customers and retail natural gas service to 330,000 customers across Avista Utilities' service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.5 million. Certain of our generating facilities are located in Montana, and we supply electricity to a small number of customers in Montana, most of whom are employees who operate one of such facilities. See “Item 2. Properties” for further information on our utility assets. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Economic Conditions and Utility Load Growth” for information on economic conditions in our service territory.

Electric Operations

In addition to providing electric distribution and transmission services, Avista Utilities generates electricity from facilities that we own and we purchase capacity, energy and fuel for generation under long-term and short-term contracts. We also sell electric capacity and energy, as well as surplus fuel in the wholesale market in connection with our resource optimization activities as described below.

As part of Avista Utilities' resource procurement and management operations in the electric business, we engage in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve our load obligations and the use of these resources to capture available economic value. We transact business in the wholesale markets by selling and purchasing electric capacity and energy, fuel for electric generation, and derivative instruments related to capacity, energy, transport and fuel. Such transactions are part of the process of matching resources with our load obligations and hedging the related financial risks. These transactions range from terms of intra-hour up to multiple years. We make continuing projections of:

- electric loads at various points in time (ranging from intra-hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data 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, we make 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 our 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 (transport) capacity contracts.

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

Avista Utilities' generation assets are interconnected through the regional transmission system and are operated on a coordinated basis to enhance load-serving capability and reliability. We provide transmission and ancillary services in eastern Washington, northern Idaho and western Montana. Transmission revenues were $15.8 million in 2014, $26.5 million in 2013 and $12.7 million in 2012. Transmission revenues for 2013 include $11.7 million from the Bonneville

Power Administration (BPA) for past use of our electric transmission system.

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Electric Requirements

Avista Utilities' peak electric native load requirement for 2014 occurred on February 6, 2014 at which time our total obligation was 2,223 MW consisting of:

- native load of 1,715 MW,
- long-term wholesale obligations of 221 MW, and
- short-term wholesale obligations of 287 MW.

At that time our maximum resource capacity available was 2,594 MW, which included:

- company-owned or controlled electric generation of 1,667 MW,
- long-term hydroelectric contracts with certain Public Utility Districts (PUDs) of 154 MW,
- long-term thermal generation contract with Lancaster Plant of 280 MW,
- other long-term wholesale contracts of 191 MW, and
- short-term wholesale purchases of 302 MW.

Electric Resources

Avista Utilities has a diverse electric resource mix of Company-owned and contracted hydroelectric projects, thermal generating facilities, wind generation facilities, and power purchases and exchanges.

At the end of 2014, our Company-owned facilities had a total net capability of 1,844 MW, of which 55 percent was hydroelectric and 45 percent was thermal. See "Item 2. Properties" for detailed information on generating facilities.

Hydroelectric Resources Avista Utilities owns and operates six hydroelectric projects on the Spokane River and two hydroelectric projects on the Clark Fork River. Hydroelectric generation is our lowest cost source per megawatt-hour (MWh) of electricity and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, we estimate that we would be able to meet approximately one-half of our total average electric requirements (both retail and long-term wholesale) with the combination of our hydroelectric generation and long-term hydroelectric purchase contracts with certain PUDs in the state of Washington. Our estimate of normal annual hydroelectric generation for 2015 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 530 average megawatts (aMW) (or 4.6 million MWhs). Hydroelectric resources provided 573 aMW for 2014, 527 aMW for 2013 and 583 aMW for 2012.

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

	2014	2013	2012
Noxon Rapids	1,968	1,581	1,823
Cabinet Gorge	1,194	1,042	1,199
Post Falls	84	85	83
Upper Falls	67	68	60
Monroe Street	103	105	102
Nine Mile	56	83	106
Long Lake	476	505	513
Little Falls	195	177	202
Total company-owned hydroelectric generation	4,143	3,646	4,088
Long-term hydroelectric contracts with PUDs	877	970	1,022
Total hydroelectric generation	5,020	4,616	5,110
Normal hydroelectric generation (1)	4,663	4,678	4,761
Percentage of normal	108 %	99 %	107 %

(1) Normal hydroelectric generation is determined by applying an upstream regulation calculation to median natural water flow information. Natural water flow is the flow of the rivers without the influence of dams, whereas regulated water flow

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takes into account any water flow changes from upstream dams due to releasing or holding back water. The calculation of normal varies annually due to the timing of upstream dam regulation throughout the year.

Thermal Resources Avista Utilities owns the following thermal resources:

- the combined cycle CT natural gas-fired Coyote Springs 2 Generation Project (Coyote Springs 2) located near Boardman, Oregon,
- a 15 percent interest in a twin-unit, coal-fired boiler generating facility, the Colstrip 3 & 4 Generating Project (Colstrip) in southeastern Montana,
- a wood waste-fired boiler generating facility known as the Kettle Falls Generating Station (Kettle Falls GS) in northeastern Washington,
- a two-unit natural gas-fired CT generating facility, located in northeastern Spokane (Northeast CT),
- a two-unit natural gas-fired CT generating facility in northern Idaho (Rathdrum CT), and
- two small natural gas-fired generating facilities (Boulder Park and Kettle Falls CT).

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

Colstrip, which is operated by PPL Montana, LLC, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2019.

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

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

See "Item 2. Properties - Avista Utilities - Generation Properties" for the nameplate rating and present generating capabilities of the above thermal resources.

The following table shows our thermal generation (in thousands of MWhs) during the year ended December 31:

	2014	2013	2012
Coyote Springs 2	1,495	1,796	1,142
Colstrip	1,464	1,227	1,499
Kettle Falls GS	259	294	209
Northeast CT, Rathdrum CT, Boulder Park and Kettle Falls CT	34	66	14
Total company-owned thermal generation	3,252	3,383	2,864
Long-term contract with Lancaster Plant	1,195	1,656	1,208
Total thermal generation	4,447	5,039	4,072

Lancaster Plant Power Purchase Agreement The Lancaster Plant is a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho, owned by an unrelated third-party. All of the output from the Lancaster Plant is contracted to us through 2026 under a power purchase agreement (PPA).

Palouse Wind PPA Palouse Wind is a wind generation project developed by Palouse Wind, LLC (Palouse Wind), and located in Whitman County, Washington. In June 2011, we entered into a 30-year PPA with Palouse Wind to acquire all of the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. The project has a nameplate capacity of approximately 105 MW and is expected to produce approximately 40 aMW. Deliveries from the project began during the fourth quarter of 2012. Generation from Palouse Wind was 335,291 MWhs in 2014 and 297,027 MWhs in 2013. We have an annual option to purchase the wind project following the 10th anniversary of its December 2012 commercial operation date. The purchase price per the PPA is a fixed price per KW of in-service capacity with a fixed decline in the price per KW over the remaining 20 year term of the agreement.

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Other Purchases, Exchanges and Sales In addition to the resources described above, we purchase and sell power under various long-term contracts and we also enter into short-term purchases and sales. Further, pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA), as amended, we are required to purchase generation from qualifying facilities. This includes, among other resources, hydroelectric projects, cogeneration projects and wind generation projects at rates approved by the UTC and the IPUC. Existing PURPA contracts expire at various times through 2022.

See “Avista Utilities Operating Statistics – Electric Operations – Electric Energy Resources” for annual quantities of purchased power, wholesale power sales and power from exchanges in 2014, 2013 and 2012. See “Electric Operations” for additional information with respect to the use of wholesale purchases and sales as part of our resource optimization process and also see "Future Resource Needs" for the magnitude of these power purchase and sales contracts in future periods.

Hydroelectric Licensing

Avista Corp. is a licensee under the Federal Power Act (FPA) as administered by the FERC, which includes regulation of hydroelectric generation resources. Excluding the Little Falls Hydroelectric Generating Project, our other seven hydroelectric plants are regulated by the FERC through two project licenses. The licensed projects are subject to the provisions of Part I of the FPA. These provisions include payment for headwater benefits, condemnation of licensed projects upon payment of just compensation, and take-over of such projects after the expiration of the license upon payment of the lesser of “net investment” or “fair value” of the project, in either case, plus severance damages.

Cabinet Gorge and Noxon Rapids are under one 45-year FERC license issued in March 2001. See “Cabinet Gorge Total Dissolved Gas Abatement Plan” in “Note 20 of the Notes to Consolidated Financial Statements” for discussion of dissolved atmospheric gas levels that exceed state of Idaho and federal water quality standards downstream of Cabinet Gorge during periods when we must divert excess river flows over the spillway and our mitigation plans and efforts.

Five of our six hydroelectric projects on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls) are under one 50-year FERC license issued in June 2009 and are referred to collectively as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. For further information see “Spokane River Licensing” in “Note 20 of the Notes to Consolidated Financial Statements.”

Future Resource Needs

Avista Utilities has operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed, which varies widely because of the factors that influence demand over intra-hour, hourly, daily, monthly and annual durations. Our average hourly load was 1,062 aMW in 2014, 1,086 aMW in 2013 and 1,075 aMW in 2012. The following is a forecast of our average annual energy requirements and resources for 2015 through 2018:

Forecasted Electric Energy Requirements and Resources
(aMW)

	2015	2016	2017	2018
Requirements:				
System load	1,068	1,074	1,084	1,091
Contracts for power sales (1)	124	91	51	39
Total requirements	1,192	1,165	1,135	1,130
Resources:				
Company-owned and contract hydro generation (2)	504	474	488	486
Company-owned and contract thermal generation (3)	723	700	723	692
Other contracts for power purchases	225	191	163	155
Total resources	1,452	1,365	1,374	1,333

Surplus resources	260	200	239	203
Additional available energy (4)	160	172	174	174
Total surplus resources	420	372	413	377

(1) The contracts for power sales decrease due to certain contracts expiring in each of these years. We are currently evaluating the future plan for the additional resources made available due to the expiration of these contracts.

(2) The forecast assumes near normal hydroelectric generation (decline in 2016 is due to changes in contracts with PUDs).

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(3) Includes our long-term contract with the owner of the Lancaster Plant. Excludes Boulder Park GS, Kettle Falls CT, Northeast CT, and Rathdrum CT as these are considered peaking facilities and are generally not used to meet our base load requirements. We generally dispatch thermal resources when operating costs are lower than short-term wholesale market prices. The decreases in availability during 2016 and 2018 at these facilities are related to scheduled maintenance at Colstrip.

(4) The combined maximum capacity of Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT is 278 MW, with estimated available energy production as indicated for each year.

In August 2013, we filed our 2013 Electric Integrated Resource Plan (IRP) with the UTC and the IPUC. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project. Highlights of the 2013 IRP include:

- In our IRP in 2011, we had certain recommendations for new renewable resources. These have been met with a 30-year PPA with Palouse Wind and the Kettle Falls GS being qualified as a renewable energy resource under the Washington state Energy Independence Act.
- Load growth is expected to be approximately 1 percent, a decline from the growth of 1.6 percent forecasted in 2011. This delays the need for a new natural gas-fired resource by one year. The decrease in expected load growth is primarily due to energy efficiency programs (using less energy to perform activities) over the next 20 years. See "Item 7. Management Discussion and Analysis – Forecasted Customer and Load Growth and Economic Conditions and Utility Load Growth" for further discussion regarding utility customer growth, load growth, and the general economic conditions in our service territory.
- Demand response (temporarily reducing the demand for energy) is included in the Preferred Resource Strategy for the first time and could provide 19 MW of peak energy reduction in the 2022 to 2027 time frame.
- 575 MW of additional natural gas-fired generation facilities are required between 2020 and 2033.
- Transmission upgrades will be needed to deliver the energy from new generation resources to the distribution lines serving customers. We will continue to participate in regional efforts to expand the region’s transmission system.

We are required to file an IRP every two years, with the next IRP expected to be filed during the third quarter of 2015. Our resource strategy may change from the 2013 IRP based on market, legislative and regulatory developments.

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

See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Environmental Issues and Other Contingencies” for information related to existing laws, as well as potential legislation that could influence our future electric resource mix.

Natural Gas Operations

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

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

Weather is a key component of our natural gas customer load. This load is highly variable and daily natural gas loads can differ significantly from the monthly forecasted load projections. We make continuing projections of our natural gas loads and assess available natural gas resources. On the basis of these projections, we plan and execute a series of transactions to hedge a portion of our customer’s projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend for multiple years into the future with the highest volumes hedged for the current and most immediate upcoming natural gas operating year (November through October). We also leave a portion of our natural gas supply requirements unhedged for purchase in the short-term spot markets.

Our purchase of natural gas supply is governed by our procurement plan. This plan is reviewed and modified annually by an internal management group. The updated plan is presented and discussed with staff in all three state jurisdictions. Communication with staff does not constitute pre-approval; however, it provides transparency to our procurement practices and offers the staff and other stakeholders an opportunity to express concerns, ask questions and learn about the factors contributing to the plan's development and subsequent execution. The plan is then presented to our Risk Management Committee (RMC) for approval. Once approval is received, the plan is implemented and monitored by our gas supply and risk management groups.

The plan's ongoing progress is also presented to UTC and IPUC staff in semi-annual meetings, and updates are given to the OPUC staff quarterly. Other stakeholders (Public Counsel, Citizen Utility Board) are invited to participate. The RMC is provided with an update on plan results and changes in their monthly meetings. These activities provide transparency for the natural gas supply procurement plan. Any material changes to the plan are documented and communicated to RMC members.

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

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

We also provide distribution transportation service to qualified, large commercial and industrial natural gas customers who purchase natural gas through third-party marketers. For these customers, we receive their purchased natural gas from such third-party marketers into our distribution system and redeliver it to the customers' premise.

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

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

Natural Gas Storage Avista Utilities owns a one-third interest in Jackson Prairie, an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 12.0 million therms, with a total working natural gas capacity of 256 million therms. As an owner, our share is one-third of the peak day deliverability and total working capacity. We also contract for additional storage capacity and delivery at Jackson Prairie from Northwest Pipeline for a portion of their one-third share of the storage project.

Natural gas storage enables us to store gas in the summer when prices are traditionally lower and withdraw during higher priced winter months. It is also used as a variable peaking resource during cold weather events.

Natural Gas Pipeline Replacement In 2011 Avista Utilities began implementation of a plan to replace certain vintages of Aldyl A natural gas pipe within our distribution systems in Washington, Idaho, and Oregon. In early 2012, we released our protocol report to each state utility commission describing our Aldyl A natural gas pipe replacement plan, proposing to replace our Aldyl A natural gas pipe across our three state jurisdictions over a 20-year period. Later in 2012, after technical workshops held by the UTC to gather perspectives on pipeline replacement programs, including the need for expedited cost recovery, the UTC required all natural gas utilities operating in Washington to file applicable pipe replacement plans. We filed our pipe replacement plan, which included our Aldyl A protocol report, with the UTC in 2013. Current annual replacement costs are approximately $16 million per year, which we expect to sustain, subject to inflation, over the 20-year period. We expect to receive cost recovery for these capital expenditures from the three jurisdictions over the life of these assets.

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Regulatory Issues

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

Since Avista Corp. is a "holding company," we are also subject to the jurisdiction of the FERC under the Public Utility Holding Company Act of 2005, which imposes certain reporting and other requirements. We, and all of our subsidiaries (whether or not engaged in any energy related business) are required to maintain books, accounts and other records in accordance with the FERC regulations and to make them available to the FERC and the state utility commissions. In addition, upon the request of any state utility commission, or of Avista Corp., the FERC would have the authority to review assignment of costs of non-power goods and administrative services among us and our subsidiaries. The FERC has the authority generally to require that rates subject to its jurisdiction be just and reasonable and in this context would continue to be able to, among other things, review transactions of any affiliated company.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a "cost of service" basis.

Rates are designed to provide an opportunity for us to recover allowable operating expenses and earn a reasonable return on "rate base." Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and retirement of utility plant and write-offs as authorized by the utility commissions. Our operating expenses and rate base are allocated or directly assigned among five regulatory jurisdictions: electric in Washington and Idaho, and natural gas in Washington, Idaho and Oregon. In general, a request for new retail rates in Washington and Idaho is made on the basis of net investment, operating expenses and revenues for a test year that ended prior to the date of the request, plus certain adjustments designed to reflect the expected revenues, expenses and net investment during the period new retail rates will be in effect. The retail rates approved by the state commissions in a rate proceeding may not provide sufficient revenues to provide recovery of costs and a reasonable return on investment for a number of reasons, including but not limited to, unexpected changes in revenues, expenses and investment following the time new retail rates are requested in the rate proceeding, and exclusion of certain costs and investment by the commission from the rate making process. Oregon currently allows the use of a forecasted test year to establish retail rates for the rate year.

Our rates for wholesale electric and natural gas transmission services are based on either "cost of service" principles or market-based rates as set forth by the FERC. See "Notes 1 and 22 of the Notes to Consolidated Financial Statements" for additional information about regulation, depreciation and deferred income taxes.

General Rate Cases Avista Utilities regularly reviews the need for electric and natural gas rate changes in each state in which we provide service. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Avista Utilities – Regulatory Matters – General Rate Cases" for information on general rate case activity.

Power Cost Deferrals Avista Utilities defers the recognition in the income statement of certain power supply costs that vary from the level currently recovered from our retail customers as authorized by the UTC and the IPUC. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Avista Utilities – Regulatory Matters – Power Cost Deferrals and Recovery Mechanisms" and "Note 22 of the Notes to Consolidated Financial Statements" for detailed information on power cost deferrals and recovery mechanisms in Washington and Idaho.

Purchased Gas Adjustment (PGA) Under established regulatory practices in each state, Avista Utilities defers the recognition in the income statement of the natural gas costs that vary from the level currently recovered from our retail customers as authorized by each of our jurisdictions. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Avista Utilities – Regulatory Matters – Purchased Gas Adjustments” and “Note 22 of the Notes to Consolidated Financial Statements” for detailed information on natural gas cost deferrals and recovery mechanisms in Washington, Idaho and Oregon.

Federal Laws Related to Wholesale Competition

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

Public utilities operating under the FPA are required to provide open and non-discriminatory access to their transmission systems to third parties and establish an Open Access Same-Time Information System to provide an electronic means by which transmission customers can obtain information about available transmission capacity and purchase transmission access. The FERC also requires each public utility subject to the rules to operate its transmission and wholesale power merchant operating functions separately and to comply with standards of conduct designed to ensure that all wholesale users, including the public utility's power merchant operations, have equal access to the public utility's transmission system. Our compliance with these standards has not had any substantive impact on the operation, maintenance and marketing of our transmission system or our ability to provide service to customers. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Competition" for further information.

Regional Transmission Organizations

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

Avista Utilities meets its FERC requirements to coordinate transmission planning activities with other regional entities through ColumbiaGrid. ColumbiaGrid is a Washington nonprofit membership corporation with an independent board formed to improve the operational efficiency, reliability, and planned expansion of the transmission grid in the Pacific Northwest. We became a member of ColumbiaGrid in 2006 during its formation. ColumbiaGrid is not an ISO, but performs only those functions that its members request, as set forth in specific agreements. Currently, ColumbiaGrid fills the role of facilitating our regional transmission planning as required in Order No. 1000 and other clarifying Orders. ColumbiaGrid and its members also work with other western organizations to address transmission planning, including WestConnect and the Northern Tier Transmission Group (NTTG). In 2011, we became a registered Planning Participant of the NTTG. We will continue to assess the benefits of entering into other functional agreements with ColumbiaGrid and/or participating in other forums to attain operational efficiencies and to meet FERC policy objectives.

Reliability Standards

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

The FERC certified the NERC as the single Electric Reliability Organization authorized to establish and enforce reliability standards and delegate authority to regional entities for the purpose of establishing and enforcing reliability standards. The FERC has approved the NERC Reliability Standards, including western region standards, making up the set of legally enforceable standards for the United States bulk electric system. The first of these reliability standards became effective in June 2007. We are required to self-certify our compliance with these standards on an annual basis and undergo regularly scheduled periodic reviews by the NERC and its regional entity, the Western Electricity Coordinating Council (WECC). Our failure to comply with these standards could result in financial penalties of up to $1 million per day per violation. Annual self-certification and audit processes to date have demonstrated our substantial compliance with these standards. Requirements relating to cyber security are continually evolving. Our compliance with version 5 of the NERC's Critical Infrastructure Protection standard is driving several physical and electronic security initiatives in our control centers, generating stations and substations. We do not expect the costs of the physical and electronic securities initiatives to have a material impact to our financial results.

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AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2014	2013	2012
ELECTRIC OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$338,697	$331,867	$315,137
Commercial	300,109	289,604	286,568
Industrial	110,775	113,632	119,589
Public street and highway lighting	7,549	7,267	7,240
Total retail	757,130	742,370	728,534
Wholesale	138,162	127,556	102,736
Sales of fuel	83,732	126,657	115,835
Other	27,467	36,071	21,067
Provision for earnings sharing (1)	(7,503)	(2,048)	—
Total electric operating revenues	$998,988	$1,030,606	$968,172
ENERGY SALES (Thousands of MWhs):			
Residential	3,694	3,745	3,608
Commercial	3,189	3,147	3,127
Industrial	1,868	1,979	2,100
Public street and highway lighting	25	26	26
Total retail	8,776	8,897	8,861
Wholesale	3,686	3,874	3,733
Total electric energy sales	12,462	12,771	12,594
ENERGY RESOURCES (Thousands of MWhs):			
Hydro generation (from Company facilities)	4,143	3,646	4,088
Thermal generation (from Company facilities)	3,252	3,383	2,864
Purchased power - hydro generation from long-term contracts with PUDs	877	970	1,022
Purchased power - thermal generation from long-term contract with Lancaster plant	1,195	1,656	1,208
Purchased power - wind generation from long-term contract with Palouse Wind	335	297	61
Purchased power - wholesale	3,208	3,452	3,995
Power exchanges	(25)	(20)	(10)
Total power resources	12,985	13,384	13,228
Energy losses and Company use	(523)	(613)	(634)
Total energy resources (net of losses)	12,462	12,771	12,594
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	324,188	321,098	318,692
Commercial	40,988	40,202	39,869
Industrial	1,385	1,386	1,395
Public street and highway lighting	531	527	503
Total electric retail customers	367,092	363,213	360,459
RESIDENTIAL SERVICE AVERAGES:			

Annual use per customer (KWh)	11,394	11,664	11,323
Revenue per KWh (in cents)	9.17	8.86	8.73
Annual revenue per customer	$1,044.76	$1,033.54	$988.84
AVERAGE HOURLY LOAD (aMW)	1,062	1,086	1,075

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AVISTA CORPORATION

AVISTA UTILITIES ELECTRIC OPERATING STATISTICS

	Years Ended December 31,		
	2014	2013	2012
REQUIREMENTS AND RESOURCE AVAILABILITY at time of system peak (MW):			
Total requirements (winter):			
Retail native load	1,715	1,669	1,554
Wholesale obligations	508	554	637
Total requirements (winter)	2,223	2,223	2,191
Total resource availability (winter)	2,594	2,767	2,618
Total requirements (summer):			
Retail native load	1,606	1,577	1,579
Wholesale obligations	691	569	906
Total requirements (summer)	2,297	2,146	2,485
Total resource availability (summer)	2,608	2,813	3,060
COOLING DEGREE DAYS: (2)			
Spokane, WA			
Actual	631	709	535
30-year average (4)	394	394	434
% of average	160 %	180 %	123 %
HEATING DEGREE DAYS: (3)			
Spokane, WA			
Actual	6,215	6,683	6,256
30-year average (4)	6,820	6,780	6,676
% of average	91 %	99 %	94 %

(1) This provision for earnings sharing is specifically related to the Idaho general rate case which was settled in March 2013. See "Item 7. Management's Discussion and Analysis - Idaho General Rate Cases" for further discussion of this provision.

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

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

(4) The 30-year average heating and cooling degree days fluctuated in 2013 due to a change in our methodology for calculating the amount. In 2013, we have switched to a rolling 30-year average whereas in prior years we only received updated 30-year average data on a periodic basis.

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AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS

	Years Ended December 31,		
	2014	2013	2012
NATURAL GAS OPERATIONS			
OPERATING REVENUES (Dollars in Thousands):			
Residential	$203,373	$206,330	$196,719
Commercial	103,179	102,225	98,994
Interruptible	2,792	2,681	2,232
Industrial	4,158	3,599	3,635
Total retail	313,502	314,835	301,580
Wholesale	228,187	194,717	158,631
Transportation	7,735	7,576	7,032
Other	7,461	8,573	6,930
Provision for earnings sharing (1)	(221)	(442)	—
Total natural gas operating revenues	$556,664	$525,259	$474,173
THERMS DELIVERED (Thousands of Therms):			
Residential	190,171	204,711	189,152
Commercial	116,748	122,245	115,083
Interruptible	5,033	5,694	4,363
Industrial	5,648	5,181	5,073
Total retail	317,600	337,831	313,671
Wholesale	545,620	524,818	586,193
Transportation	162,311	159,976	154,704
Interdepartmental and Company use	411	418	381
Total therms delivered	1,025,942	1,023,043	1,054,949
SOURCES OF NATURAL GAS DELIVERED (Thousands of Therms):			
Purchases	902,040	834,068	919,684
Storage - injections	(99,550)	(97,338)	(105,904)
Storage - withdrawals	68,722	129,006	93,850
Natural gas for transportation	162,311	159,976	154,704
Distribution system losses	(7,581)	(2,669)	(7,385)
Total natural gas delivered	1,025,942	1,023,043	1,054,949
NUMBER OF RETAIL CUSTOMERS (Average for Period):			
Residential	291,928	288,708	286,522
Commercial	34,047	33,932	33,763
Interruptible	37	38	38
Industrial	264	259	263
Total natural gas retail customers	326,276	322,937	320,586
RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (therms)	651	709	660
Revenue per therm (in dollars)	$1.07	$1.01	$1.04
Annual revenue per customer	$696.66	$714.67	$686.57

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AVISTA CORPORATION

AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS

	Years Ended December 31,		
	2014	2013	2012
HEATING DEGREE DAYS: (2)			
Spokane, WA			
Actual	6,215	6,683	6,256
30-year average (3)	6,820	6,780	6,676
% of average	91 %	99 %	94 %
Medford, OR			
Actual	3,382	4,576	4,182
30-year average (3)	4,539	4,539	4,422
% of average	75 %	101 %	95 %

(1) This provision for earnings sharing is specifically related to the Idaho general rate case which was settled in March 2013. See "Item 7. Management's Discussion and Analysis - Idaho General Rate Cases" for further discussion of this provision.

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

(3) The 30-year average heating degree days fluctuated in 2013 due to a change in our methodology for calculating the amount. In 2013, we have switched to a rolling 30-year average whereas in prior years we only received updated 30-year average data on a periodic basis.

ALASKA ELECTRIC LIGHT AND POWER COMPANY

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

AEL&P owns and operates electric generation, transmission and distribution facilities located in Juneau. AEL&P operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity as of December 31, 2014. AEL&P owns four of these generation facilities (totaling 24.7 MW of capacity) and has a power purchase commitment for the output of the Snettisham hydroelectric project (totaling 78 MW of capacity). The Snettisham power purchase agreement is accounted for as a capital lease.

The Snettisham hydroelectric project is AEL&P’s primary generation facility and the main power source for Juneau, supplying approximately two-thirds of the area’s electricity. The Snettisham hydroelectric project was constructed and operated by the federal government and subsequently purchased by the Alaska Industrial Development and Export Authority (AIDEA). AEL&P has a long-term power purchase agreement and operating and maintenance agreement with the AIDEA to operate and maintain the facility. This power purchase agreement is a take-or-pay obligation expiring in December 2038, to purchase all the output of the 78 MW Snettisham hydroelectric project. AIDEA issued $100.0 million in revenue bonds (of which $70.0 million was outstanding as of December 31, 2014), to finance its acquisition of the project and the payments by AEL&P are designed to be more than sufficient to enable the AIDEA to pay the principal of and interest on its revenue bonds, maturing in January 2034. The payments by AEL&P under the agreement are unconditional, notwithstanding any suspension, reduction or curtailment of the operation of the project. For accounting purposes, this power purchase agreement is treated as a capital lease and as of December 31, 2014, the capital lease obligation was $70.0 million. Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project at any time for the principal amount of the bonds outstanding at that time. See "Note 14 of the Notes to Consolidated Financial Statements" for further discussion of the Snettisham capital lease obligation.

As of December 31, 2014, AEL&P also had 93.9 MW of diesel generating capacity from three facilities to provide back-up service to firm customers when necessary.

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

	Second half of 2014	Full 12 months of 2014
Snettisham	119	276
Lake Dorothy	54	85
Salmon Creek	16	25
Annex Creek	14	28
Gold Creek	4	6
Total hydroelectric generation	207	420
Normal hydroelectric generation	211	430
Percentage of normal	98 %	98 %

Only the hydroelectric generation for the second half of 2014 in the table above was included in Avista Corp.'s overall results for 2014. The full 12 months of 2014 in the table above is presented for information purposes only.

As of December 31, 2014, AEL&P served 16,394 customers. AEL&P’s customer classes include residential, small commercial, large commercial, governmental and street lighting customer classes. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AEL&P’s customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AEL&P maintains separate rate tariffs for each of its customer classes, as well as separate seasonal rates.

As of December 31, 2014, AEL&P had 59 full-time employees and employs approximately 15-18 temporary, seasonal employees each year. Approximately half of AEL&P’s full-time employees are members of the International Brotherhood of Electrical Workers (IBEW) and subject to a collective bargaining agreement.

AEL&P’s operations are subject to regulation by the RCA with respect to rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities. Rate adjustments for AEL&P’s customers require approval by the RCA pursuant to RCA regulations. AEL&P's last general rate case was filed in 2010 and approved by the RCA in 2011. The RCA approved a capital structure including 53.8 percent equity and an authorized return on equity of 12.875 percent. We expect that AEL&P will maintain a similar capital structure going forward.

AEL&P is also subject to the jurisdiction of the FERC concerning the permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Salmon Creek and Annex Creek hydroelectric projects) expires in 2018. Since AEL&P has no electric interconnection with other utilities and makes no wholesale sales, it is not subject to general FERC jurisdiction.

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

OTHER BUSINESSES

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

	2014	2013
Spokane Energy	$30,404	$42,829
Avista Energy	—	12,399
METALfx	12,065	11,105
Steam Plant and Courtyard Office Center	7,278	7,055
Alaska companies (AERC and AJT Mining)	7,507	—
Avista Capital - standalone	13,221	420
Other	9,735	7,474
Total	$80,210	$81,282

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Spokane Energy is a special purpose limited liability company and all of its membership capital is owned by Avista Corp. Spokane Energy was formed in December 1998, to assume ownership of a fixed rate electric capacity contract between Avista Corp. and Portland General Electric Company. Of the total assets for Spokane Energy, the fixed rate electricity capacity contract represents $28.2 million and $40.6 million for 2014 and 2013, respectively, and the likelihood of this asset being at risk of impairment is remote. In addition to the assets above, Spokane Energy has nonrecourse long-term debt outstanding in the amount of $1.4 million and $17.8 million at December 31, 2014 and 2013, respectively, related to the acquisition of the fixed rate electric capacity contract. The final payment was made in January 2015.

Avista Energy is a former electricity and natural gas marketing, trading and resource management business, which is a subsidiary of Avista Capital. This subsidiary has not been active since 2009; however, it continues to incur legal fees as it defends its actions related to legal proceedings in the Pacific Northwest Refund Proceeding. During 2014, Avista Energy finalized a settlement agreement in its other legal proceedings including the FERC Inquiry, the California Refund Proceeding and the California Attorney General Complaint (the “Lockyer Complaint”). See "Note 20 of the Notes to the Consolidated Financial Statements" for further detail regarding these legal proceedings. The assets associated with Avista Energy as of December 31, 2013 were deferred tax assets related to its former operations.

AM&D doing business as METALfx performs custom sheet metal fabrication of electronic enclosures, parts and systems for the computer, construction, telecom, renewable energy and medical industries.

Steam Plant and Courtyard Office Center consist of real estate investments (primarily mixed use commercial and retail office space).

As of July 1, 2014 we own AERC and AJT Mining, which is a wholly-owned subsidiary of AERC and is an inactive mining company holding certain properties.

The assets at Avista Capital - standalone as of December 31, 2014 primarily consist of the escrow receivables related to the sale of Ecova on June 30, 2014. See "Note 5 of the Notes to Consolidated Financial Statements" for further detail regarding this transaction.

Our other investments and operations include emerging technology venture capital funds.

Over time as opportunities arise, we dispose of investments and phase out operations that do not fit with our overall corporate strategy. However, we may invest incremental funds to protect our existing investments and invest in new businesses that we believe fit with our overall corporate strategy.

We are focused on discovering new ways to accelerate growth for Avista Corp. within our core utility business and related businesses and are planning to incur $2.0 million to $3.0 million per year exploring opportunities to develop new markets and ways for customers to improve the use of electricity and natural gas for commercial productivity and transportation. We may also make other targeted investments that will help us gain strategic insights to build new growth platforms.

In particular, Salix LNG is exploring markets that could be served with liquefied natural gas, primarily in western North America. These markets include power generation, marine bunkering and transportation fuels.

Also, our acquisition of AERC provides us a platform to explore strategic opportunities to bring natural gas to Southeast Alaska.

ITEM 1A. RISK FACTORS

RISK FACTORS

The following factors could have a significant impact on our operations, results of operations, financial condition or cash flows. These factors could cause actual results or outcomes to differ materially from those discussed in our reports filed with the Securities and Exchange Commission (including this Annual Report on Form 10-K), and elsewhere. Please also see “Forward-Looking Statements” for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

Weather (temperatures, precipitation levels and storms) has a significant effect on our results of operations, financial condition and cash flows.
Weather impacts are described in the following subtopics:
- certain retail electricity and natural gas sales,

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- the cost of natural gas supply,
- the cost of power supply, and
- damage to facilities.

Certain retail electricity and natural gas sales volumes vary directly with changes in temperatures. We normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter) in the Pacific Northwest. In general, warmer weather in the heating season and cooler weather in the cooling season will reduce our customers' energy demand and retail operating revenues.

The cost of natural gas supply tends to increase with higher demand during periods of cold weather. Increased costs adversely affect cash flows when we purchase natural gas for retail supply at prices above the amount then allowed for recovery in retail rates. We defer differences between actual natural gas supply costs and the amount currently recovered in retail rates and we are generally allowed to recover substantially all of these differences after regulatory review. However, these deferred costs require cash outflows from the time of natural gas purchases until the costs are later recovered through retail sales. Inter-regional natural gas pipelines and competition for supply can allow demand-driven price volatility in other regions of North America to affect prices in our region, even though there may be less extreme weather conditions in our area.

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

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

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

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

Damage to facilities may be caused by severe weather, such as snow, ice, wind storms or avalanches. The cost to implement rapid or any repair to such facilities can be significant. Overhead electric lines are most susceptible to damage caused by severe weather.

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

We have experienced higher costs for utility operations in each of the last several years with the exception of 2013 which saw a slight decrease from 2012 actual costs. We have also made significant capital investments into utility plant assets. Our ability to recover these costs depends on the amount and timeliness of retail rate changes allowed by regulatory agencies. We expect to periodically file for rate increases with regulatory agencies to recover our costs and provide an opportunity to earn a reasonable rate of return for shareholders. If regulators grant substantially lower rate increases than our requests in the future or if deferred costs are disallowed, it could have a negative effect on our operating revenues, net income and cash flows.

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

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

- Our obligation to serve our retail customers at rates set through the regulatory process. We cannot change retail rates to reflect current energy prices unless and until we receive regulatory approval.
- Customer demand, which is beyond our control because of weather, customer choices, prevailing economic conditions and other factors.
- Some of our energy supply cost is fixed by the nature of the energy-producing assets or through contractual arrangements. However, a significant portion of our energy resource costs are not fixed.

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

When we enter into fixed price energy commodity transactions for future delivery, we are subject to credit terms that may require us to provide collateral to wholesale counterparties related to the difference between current prices and the agreed upon fixed prices. These collateral requirements can place significant demands on our cash flows or borrowing arrangements. Price volatility can cause collateral requirements to change quickly and significantly.

Cash flow deferrals related to energy commodities can be significant. We are permitted to collect from customers only amounts approved by regulatory commissions. However, our costs to provide energy service can be much higher or lower than the amounts currently billed to customers. We are permitted to defer most of this difference for review by the regulatory commissions who have discretion as to the extent and timing of future recovery or refund to customers. Power and natural gas costs higher than those recovered in retail rates reduce cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect our results of operations.

We defer income statement recognition and recovery from customers of certain power and natural gas costs that are higher or lower than what are currently authorized in retail rates by regulators. These power and natural gas costs are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators.

Despite the opportunity to recover deferred power and natural gas costs, our operating cash flows can be negatively affected until these costs are recovered from customers.

Our energy resource risk management processes can cause volatility in our cash flows and results of operations. We engage in active hedging and resource optimization practices to reduce energy cost volatility and economic exposure related to commodity price fluctuations. We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity and natural gas, as well as forecasted excess or deficit energy positions and inventories of natural gas. We use physical energy contracts and derivative instruments, such as forwards, futures, swaps and options traded in the over-the-counter markets or on exchanges. We cannot and do not attempt to fully hedge our energy resource assets or our forecasted net positions for various time horizons. To the extent we have positions that are not hedged, or if hedging positions do not fully match the corresponding purchase or sale, fluctuating commodity prices could have a material effect on our operating revenues, resource costs, derivative assets and liabilities, and operating cash flows. In addition, actual loads and resources typically vary from forecasts, sometimes to a significant degree, which require additional transactions or dispatch decisions that impact cash flows.

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

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

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

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

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

We rely on credit from financial institutions for short-term borrowings. We need adequate levels of credit with financial institutions for short-term liquidity. We have a $400.0 million committed line of credit that is scheduled to expire in April 2019. Our subsidiary AEL&P has a committed line of credit in the amount of $25.0 million with an expiration date of November 2019. There is no assurance that we will have access to credit beyond these expiration dates. The committed line of credit agreements contain customary covenants and default provisions. In the event of 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.

We hedge a portion of our interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements. We increased the use of interest rate swaps in 2013 and 2014. If market interest rates decrease below the interest rates we have locked in, this will result in a liability related to our interest rate swap agreements, which can be significant. As of December 31, 2014, we had a net interest rate derivative liability of $76.6 million, which increased significantly in 2014 due to declining long-term interest rates. We did not have any U.S. Treasury lock agreements outstanding as of December 31, 2014. We may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. Settlement of interest rate derivative instruments in a liability position could require a significant amount of cash, which could negatively impact our liquidity and short-term credit availability and increase interest expense over the term of the associated debt.

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

We are subject to various operational and event risks.

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

- blackouts or disruptions to distribution, transmission or transportation systems,
- unplanned outages at generating plants,
- fuel cost and availability, including delivery constraints,
- explosions, fires, accidents, or mechanical breakdowns that may occur while operating and maintaining our generation, transmission and distribution systems, and

- natural disasters that can disrupt energy generation, transmission and distribution and general business operations. Disasters may affect the general economy, financial and capital markets, specific industries, or our ability to conduct business. As protection against operational and event risks, we maintain business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and we seek to negotiate indemnification arrangements with contractors for certain event risks. However, insurance or indemnification agreements may not be adequate to protect us against liability, extra expenses and operating disruptions from all of the operational and event risks described above. In addition, we are subject to the risk that insurers and/or other parties will dispute or be unable to perform on their obligations to us.

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

In the course of our operations, we rely on interconnected technology systems for operation of our generating plants, electric transmission and distribution systems, natural gas distribution systems, customer billing and customer service, accounting and other administrative processes and compliance with various regulations.

There are various risks associated with technology systems such as hardware or software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other deliberate or inadvertent human errors. In particular, cyber attacks, terrorism or other malicious acts could damage, destroy or disrupt these systems. Additionally, the facilities and systems of clients, suppliers and third party service providers could be vulnerable to these same risks and, to the extent of interconnection to our technology, may impact us. Any failure, unexpected, or unauthorized unavailability of technology systems could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. Any of the above could also result in the loss or release of confidential customer information or other proprietary data that could adversely affect our reputation, competitiveness, and result in costly litigation and impact on our results of operations. As these potential cyber attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems and respond to emerging concerns.

Terrorist attacks could also be directed at physical electric and natural gas facilities, as well as technology systems.

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

We expect to continue to be affected by legislation at the national, state and local level, as well as by administrative rules and requirements published by government agencies, including but not limited to the FERC, the EPA and state regulators. We are also subject to NERC and WECC reliability standards. The FERC, the NERC and the WECC may perform periodic audits of the Company. Failure to comply with the FERC, the NERC, or the WECC requirements can result in financial penalties of up to $1 million per day per violation.

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

Actions or limitations to address concerns over the long-term global and our utilities' service area climate changes may affect our operations and financial performance.

Legislative developments and advocacy at the state, national and international levels concerning climate change and other environmental issues could have significant impacts on our operations. The electric utility industry is one of the largest and most immediate industries to be more heavily regulated in some proposals. For example, various legislative proposals have been made to limit or place further restrictions on byproducts of combustion, including sulfur dioxide, nitrogen oxide, carbon dioxide, and other greenhouse gases and mercury emissions. Such proposals, if adopted, could restrict the operation and raise the cost of our power generation resources.

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

- increase the operating costs of generating plants,
- increase the lead time and capital costs for the construction of new generating plants,
- require modification of our existing generating plants,

- require existing generating plant operations to be curtailed or shut down,
- reduce the amount of energy available from our generating plants,
- restrict the types of generating plants that can be built or contracted with, and
- require construction of specific types of generation plants at higher cost.

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

In the normal course of our business, we have matters that are the subject of ongoing litigation, mediation, investigation and/or negotiation. We cannot predict the ultimate outcome or potential impact of any particular issue, including the extent, if any, of insurance coverage or that amounts payable by us may be recoverable through the ratemaking process. We are subject to environmental regulation by federal, state and local authorities related to our past, present and future operations. See “Note 20 of the Notes to Consolidated Financial Statements” for further details of these matters.

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

In February 2015 we implemented new customer information and work management systems. 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. These implementations have resulted in certain changes to business processes and internal controls. There are inherent risks associated with replacing and changing these types of systems, such as delayed and / or inaccurate customer bills, potential disruption of our business, substantial unplanned costs and the potential lack of recovery through rates which could have a material adverse effect on our results of operations, financial condition and cash flows.

Our acquisition of AERC may not achieve its intended results.

On July 1, 2014, we completed the acquisition of AERC, and its subsidiary, AEL&P, the sole provider of electric services to 16,394 customers in Juneau, Alaska. Achieving the anticipated earnings contribution from AERC is subject to numerous uncertainties, including market conditions and risks related to AERC's business. This transaction could result in increased costs, decreases in the expected revenues from AERC, the impairment of goodwill or other assets, and diversion of management time and resources, which could have a material adverse effect on our results of operations, financial condition and cash flows.

A majority of AEL&P’s hydroelectric power generation is provided by a single facility that is subject to a long-term power purchase agreement and operating and maintenance agreement in connection with which AEL&P is required to make certain payments.

While AEL&P operates several hydroelectric power generation facilities and has diesel generating capacity from multiple facilities to provide backup service to firm customers when necessary, a single hydroelectric power generation facility, the Snettisham hydroelectric project, provides approximately two-thirds of AEL&P’s hydroelectric power generation. Any issues that negatively affect the Snettisham hydroelectric project’s ability to generate or transmit power, any decrease in the demand for the power generated by the Snettisham hydroelectric project or any loss by AERC or its subsidiaries of their contractual rights with respect thereto or other adverse effect thereon could negatively affect our results of operations, financial condition and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

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

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ITEM 2. PROPERTIES
AVISTA UTILITIES
Substantially all of Avista Utilities' properties are subject to the lien of Avista Corp.'s mortgage indenture.
Our utility electric properties, located in the states of Washington, Idaho, Montana and Oregon, include the following:
Generation Properties

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations (River)			
Washington:			
Long Lake (Spokane)	4	70.0	88.0
Little Falls (Spokane)	4	32.0	35.6
Nine Mile (Spokane) (3)	4	26.4	22.4
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork) (4)	4	265.0	273.0
Post Falls (Spokane)	6	14.8	15.4
Montana:			
Noxon Rapids (Clark Fork)	5	487.8	562.4
Total Hydroelectric		920.8	1,022.0
Thermal Generating Stations (cycle, fuel source)			
Washington:			
Kettle Falls GS (combined-cycle, wood waste) (5)	1	50.7	53.5
Kettle Falls CT (combined-cycle, natural gas) (5)	1	7.2	6.9
Northeast CT (simple-cycle, natural gas)	2	61.8	64.8
Boulder Park GS (simple-cycle, natural gas)	6	24.6	24.0
Idaho:			
Rathdrum CT (simple-cycle, natural gas)	2	166.5	166.5
Montana:			
Colstrip Units 3 and 4 (simple-cycle, coal) (6)	2	233.4	222.0
Oregon:			
Coyote Springs 2 (combined-cycle, natural gas)	1	287.0	284.4
Total Thermal		831.2	822.1
Total Generation Properties		1,752.0	1,844.1

(1) Nameplate Rating, also referred to as “installed capacity,” is the manufacturer’s assigned power capability under specified conditions.

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2014.

(3) There are four units at the Nine Mile plant; however, Units 1 and 2 are not operating due to a mechanical failure. A project is underway to replace these units and restore capability. The present capability disclosed above represents the capability of the two operating units, which have a nameplate rating of 18 MW combined.

(4) For Cabinet Gorge, we have water rights permitting generation up to 265 MW. However, if natural stream flows will allow for generation above our water rights we are able to generate above our water rights. If natural stream

flows only allow for generation at or below 265 MW, we are limited to generation of 265 MW. The present capability disclosed above represents the capability based on maximum stream flow conditions when we are allowed to generate above our water rights.

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

(6) Jointly owned; data refers to our 15 percent interest.

Electric Distribution and Transmission Plant

Avista Utilities owns and operates approximately 19,000 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of 676 miles of 230 kV line and 1,553 miles of 115 kV line. We also own an 11 percent interest in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution systems also include numerous substations with transformers, switches, monitoring and metering devices, and other equipment.

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

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

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

Natural Gas Plant

Avista Utilities has natural gas distribution mains of approximately 3,400 miles in Washington, 2,000 miles in Idaho and 2,300 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 50 miles in Oregon. Our natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

We own a one-third interest in Jackson Prairie, an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 12.0 million therms, with a total working natural gas capacity of 256 million therms. As an owner, our share is one-third of the peak day deliverability and total working capacity. Natural gas storage enables us to store gas in the summer when prices are traditionally lower and withdraw during higher priced winter months. Natural gas storage is also used as a variable peaking resource during cold weather events.

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ALASKA ELECTRIC LIGHT AND POWER COMPANY

Substantially all of AEL&P's utility properties are subject to the lien of the AEL&P mortgage indenture.

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

Generation Properties and Transmission and Distribution Lines

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations			
Snettisham (3)	3	78.2	78.2
Lake Dorothy	1	14.3	14.3
Salmon Creek	1	8.4	5.0
Annex Creek	2	4.1	3.6
Gold Creek	3	1.6	1.6
Total Hydroelectric		106.6	102.7
Diesel Generating Stations			
Lemon Creek	11	61.4	57.5
Auke Bay	3	36.2	28.3
Gold Creek	5	8.2	8.1
Total Diesel		105.8	93.9
Total Generation Properties		212.4	196.6

(1) Nameplate Rating, also referred to as “installed capacity,” is the manufacturer’s assigned power capability under specified conditions.

(2) Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2014.

(3) AEL&P does not own this generating facility but has a power purchase agreement under which it has the right to purchase, and the obligation to pay for (whether or not energy is received), all of the capacity and energy of this facility. See further information at "Part 1. Item 1. Business - AEL&P Overview."

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

ITEM 3. LEGAL PROCEEDINGS

See “Note 20 of Notes to Consolidated Financial Statements” for information with respect to legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

Avista Corp. Market Information and Dividend Policy

Avista Corp.'s common stock is currently listed on the New York Stock Exchange under the ticker symbol “AVA.” As of January 31, 2015, there were 9,238 registered shareholders of our common stock.

Avista Corp.'s 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.

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

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

- certain covenants applicable to preferred stock (when outstanding) contained in the Company’s Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements (see Item 7. Management's Discussion and Analysis - "Capital Resources" for compliance with these covenants),
- the hydroelectric licensing requirements of section 10(d) of the FPA (see “Note 1 of Notes to Consolidated Financial Statements”), and
- certain requirements under the OPUC approval of the AERC acquisition. After the initial year, the OPUC does not permit one-time or special dividends from AERC to Avista Corp. and does not permit Avista Utilities' total equity to total capitalization to be less than 40 percent, without approval from the OPUC. However, the OPUC approval does allow for regular distributions of AERC earnings to Avista Corp. as long as AERC remains sufficiently capitalized and insured.

On February 6, 2015, Avista Corp.’s Board of Directors declared a quarterly dividend of $0.33 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 $0.3175 per share.

For additional information, see “Notes 1, 17, 18 and 19 of Notes to Consolidated Financial Statements.”

The following table presents quarterly high and low stock prices as reported on the consolidated reporting system, as well as dividend information:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2014				
Dividends paid per common share	$0.3175	$0.3175	$0.3175	$0.3175
Trading price range per common share:				
High	$30.83	$33.58	$33.60	$37.37
Low	$27.71	$30.02	$30.35	$30.55
2013				
Dividends paid per common share	$0.305	$0.305	$0.305	$0.305
Trading price range per common share:				
High	$27.48	$29.26	$29.21	$28.45
Low	$24.10	$25.68	$25.55	$25.88

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

Issuer Purchases of Equity Securities

On June 13, 2014, our Board of Directors approved the repurchase of up to 4 million shares of the Company's outstanding common stock, assuming the closure of the Ecova transaction (2014 program). Repurchases of common stock under the 2014 program commenced on July 7, 2014 and the 2014 program expired on December 31, 2014. Repurchases were made in the open market or in privately negotiated transactions. Through December 31, 2014, we repurchased 2,529,615 shares at a total cost of $79.9 million and an average cost of $31.57 per share. All repurchased shares under the 2014 program reverted to the status of authorized but unissued shares.

The following table provides information about share repurchases that we made during the three months ended December 31, 2014 (in thousands, except per share amounts):

	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program
October 1 to October 31, 2014	606	$31.20	606	1,470
November 1 to November 30, 2014	—	—	—	1,470
December 1 to December 31, 2014	—	—	—	1,470
Total	606	$31.20	606	1,470

On December 16, 2014, our Board of Directors approved the repurchase of up to 800,000 shares of the Company's outstanding common stock, commencing on January 2, 2015, and continuing through March 31, 2015 (first quarter 2015 program). The number of shares repurchased through the first quarter 2015 program will be in addition to the number of shares repurchased under the 2014 program, which expired on December 31, 2014. The parameters of the first quarter 2015 program are consistent with the parameters of the 2014 program. We have not repurchased any shares under the first quarter 2015 program through January 31, 2015. All repurchased shares, if any, will revert to the status of authorized but unissued shares.

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ITEM 6. SELECTED FINANCIAL DATA

(in thousands, except per share data and ratios)	Years Ended December 31,				
	2014	2013	2012	2011	2010
Operating Revenues:					
Avista Utilities	$1,413,499	$1,403,995	$1,354,185	$1,443,322	$1,419,646
AEL&P	21,644	—	—	—	—
Other	39,219	39,549	38,953	40,410	61,067
Intersegment eliminations	(1,800)	(1,800)	(1,800)	(1,800)	(24,008)
Total	$1,472,562	$1,441,744	$1,391,338	$1,481,932	$1,456,705
Income (Loss) from Continuing Operations (pre-tax):					
Avista Utilities	$239,976	$232,572	$188,778	$202,373	$198,200
AEL&P	6,221	—	—	—	—
Other	6,391	(1,483)	(1,680)	4,714	5,669
Total	$252,588	$231,089	$187,098	$207,087	$203,869
Net income from continuing operations	$119,866	$104,333	$76,803	$90,658	$85,058
Net income from discontinued operations	72,411	7,961	1,997	12,881	9,890
Net income	$192,277	$112,294	$78,800	$103,539	$94,948
Net income attributable to noncontrolling interests	$(236)	$(1,217)	$(590)	$(3,315)	$(2,523)
Net Income (Loss) attributable to Avista Corporation shareholders:					
Avista Utilities	$113,263	$108,598	$81,704	$90,902	$86,681
AEL&P	3,152	—	—	—	—
Ecova - Discontinued operations	72,390	7,129	1,825	9,671	7,433
Other	3,236	(4,650)	(5,319)	(349)	(1,689)
Net income attributable to Avista Corp. shareholders	$192,041	$111,077	$78,210	$100,224	$92,425
Average common shares outstanding, basic	61,632	59,960	59,028	57,872	55,595
Average common shares outstanding, diluted	61,887	59,997	59,201	58,092	55,824
Common shares outstanding at year-end	62,243	60,077	59,813	58,423	57,120
Earnings per common share attributable to Avista Corp. shareholders, basic:					
Earnings per common share from continuing operations	$1.94	$1.74	$1.30	$1.56	$1.53
Earnings per common share from discontinued operations	1.18	0.11	0.02	0.17	0.13
Total earnings per common share attributable to Avista Corp. shareholders, basic	$3.12	$1.85	$1.32	$1.73	$1.66
Earnings per common share attributable to Avista Corp. shareholders, diluted:					
Earnings per common share from continuing operations	$1.93	$1.74	$1.30	$1.56	$1.52
Earnings per common share from discontinued operations	1.17	0.11	0.02	0.16	0.13
Total earnings per common share attributable to Avista Corp. shareholders, diluted	$3.10	$1.85	$1.32	$1.72	$1.65

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(in thousands, except per share data and ratios)	Years Ended December 31,				
	2014	2013	2012	2011	2010
Dividends declared per common share	$1.27	$1.22	$1.16	$1.10	$1.00
Book value per common share	$23.84	$21.61	$21.06	$20.30	$19.71
Total Assets at Year-End:					
Avista Utilities	$4,367,926	$3,940,998	$3,894,821	$3,809,446	$3,589,235
AEL&P	264,195	—	—	—	—
Other	80,210	81,282	95,638	112,145	129,774
Total (1)	$4,712,331	$4,022,280	$3,990,459	$3,921,591	$3,719,009
Long-Term Debt and Capital Leases (including current portion)	$1,498,486	$1,272,783	$1,228,739	$1,177,300	$1,101,857
Nonrecourse Long-Term Debt of Spokane Energy (including current portion)	$1,431	$17,838	$32,803	$46,471	$58,934
Long-Term Debt to Affiliated Trusts	$51,547	$51,547	$51,547	$51,547	$51,547
Total Avista Corp. Shareholders' Equity	$1,483,671	$1,298,266	$1,259,477	$1,185,701	$1,125,784
Ratio of Earnings to Fixed Charges (2)	3.39	3.02	2.48	2.81	2.68

(1) The total assets at year-end for the years 2013 to 2010 exclude the total assets associated with Ecova of $339.6 million, $322.7 million, $292.9 million and $221.1 million, respectively.

(2) See Exhibit 12 for computations.

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

Business Segments

As of December 31, 2014, we have two reportable business segments, Avista Utilities and AEL&P. We also have other businesses which do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp. See "Part I, Item 1. Business - Company Overview" for further discussion of our business segments.

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

	2014	2013	2012
Avista Utilities	$113,263	$108,598	$81,704
Alaska Electric Light and Power Company	3,152	—	—
Ecova - Discontinued operations (1)	72,390	7,129	1,825
Other	3,236	(4,650)	(5,319)
Net income attributable to Avista Corporation shareholders	$192,041	$111,077	$78,210

(1) The results for the year ended December 31, 2014 include the net gain on sale of Ecova of $69.7 million.

Executive Level Summary

Overall Results

Net income attributable to Avista Corporation shareholders was $192.0 million for 2014, an increase from $111.1 million for 2013. The increase was primarily due to the disposition of Ecova, which resulted in the recognition of a $69.7 million net gain. In addition, we recognized a $15.0 million pre-tax gain during the second quarter related to the settlement of the California power markets litigation involving Avista Energy. The gain from the litigation settlement was partially offset by a pre-tax contribution of $6.4 million of the proceeds to the Avista Foundation, a charitable organization funded by Avista Corp.

Earnings at Avista Utilities increased due to the implementation of general rate increases in each of our jurisdictions, lower net power supply costs and a decrease in interest expense, partially offset by the provision for earnings sharing in Idaho. There were also expected increases in other operating expenses, depreciation and amortization and taxes other than income taxes. Utility results for 2013 also included the net benefit from the settlement with the BPA.

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.

Forecasted Customer and Load Growth

Based on our forecast for 2015 through 2018 for Avista Utilities' service area, we expect annual electric customer growth to average 1.2 percent, within a forecast range of 0.8 percent to 1.6 percent. We expect annual natural gas customer growth to average 1.0 percent, within a forecast range of 0.5 percent to 1.5 percent. We anticipate retail electric load growth to average 0.8 percent, within a forecast range of 0.5 percent and 1.1 percent. We expect natural gas load growth to average 1.3 percent, within a forecast range of 0.8 percent and 1.8 percent. The forecast ranges reflect (1) the inherent uncertainty associated with the economic assumptions on which forecasts are based and (2) natural gas customer and load growth has been historically more volatile.

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In AEL&P's service area, we expect annual residential customer growth to be in a narrow range around 0.4 percent for 2015 through 2018. We expect no significant growth in commercial and government customers over the same period. We anticipate that average annual total load growth will be in a narrow range around 0.9 percent, with residential load growth averaging about 0.6 percent; commercial about 1.2 percent; and government about 1.0 percent. For further discussion regarding utility customer growth, load growth, and the general economic conditions in our service territory, see "Economic Conditions and Utility Load Growth."

See also "Competition" for a discussion of competitive factors that could affect our results of operations in the future.

General Rate Cases (GRC)

In our utility operations (both Avista Utilities and AEL&P), 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. See further discussion under "Regulatory Matters."

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. Avista Utilities' cash-basis capital expenditures (per the Consolidated Statement of Cash Flows) were $323.9 million for 2014. Our accrual-basis capital expenditures were $352.3 million for 2014. We expect Avista Utilities' capital expenditures to be about $375 million for 2015 and $350 million in 2016. AEL&P's capital expenditures were $1.6 million for the six month period July 1, 2014 to December 31, 2014. We expect to spend approximately $15 million for each of 2015 and 2016 related to capital expenditures at AEL&P. These estimates of capital expenditures are subject to continuing review and adjustment (see further discussion under “Capital Expenditures”).

Alaska Energy and Resources Company Acquisition

On July 1, 2014, we completed our acquisition of AERC, located in Juneau, Alaska, of which AEL&P is a wholly-owned subsidiary. As of July 1, 2014 AERC is a wholly-owned subsidiary of Avista Corp.

In connection with the closing, we issued 4,501,441 new shares of common stock to the shareholders of AERC based on a contractual formula that resulted in a price of $32.46 per share, reflecting a purchase price of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments.

This transaction resulted in the recording of $52.7 million in goodwill during 2014.

Also, our acquisition of AERC provides us a platform to explore strategic opportunities to bring natural gas to Southeast Alaska.

For additional information regarding the AERC transaction, see “Note 4 of the Notes to Consolidated Financial Statements.”

Ecova Disposition

On May 29, 2014, Avista Capital, Inc., our non-regulated subsidiary, entered into a definitive agreement to sell its interest in Ecova to Cofely USA Inc., an indirect subsidiary of GDF SUEZ, a French multinational utility company. The sales transaction was completed on June 30, 2014, for a sales price of $335.0 million in cash, less the payment of debt and other customary closing adjustments. At the closing of the transaction on June 30, 2014, Ecova became a wholly-owned subsidiary of Cofely USA Inc.

The purchase price of $335.0 million, as adjusted, was divided among the security holders of Ecova, including minority shareholders and option holders, pro rata based on ownership. Approximately $16.8 million (5 percent of the purchase price) will be held in escrow for 15 months from the closing of the transaction to satisfy certain indemnification obligations under the merger agreement, and an additional $1.0 million is being held in escrow pending resolution of adjustments to working capital, which is expected to be completed in early 2015.

Avista Capital and Cofely USA Inc. agreed to make an election under Code Section 338(h)(10) with respect to the purchase and sale of Ecova to allocate the merger consideration among the assets of Ecova acquired in the merger.

When all remaining escrow amounts are released, the sales transaction is expected to provide cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.5 million and result in a net gain of $69.7 million. The Company expects to receive the full amount of its portion of the remaining escrow accounts; therefore, these amounts are included in the gain calculation.

On July 1, 2014, we utilized a portion of the proceeds from the Ecova sales transaction to pay off the outstanding balance owed on our committed line of credit and we initiated a common stock share repurchase program.

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Stock Repurchase Programs

During 2014, Avista Corp. repurchased 2,529,615 shares of our outstanding common stock at a total cost of $79.9 million and an average cost of $31.57 per share through our 2014 stock repurchase program. We did not make any repurchases under this program subsequent to October 2014.

Avista Corp. initiated a second stock repurchase program commencing on January 2, 2015 which will continue through March 31, 2015 for the repurchase of up to 800,000 shares of our outstanding common stock. We have not repurchased any shares under this program through January 31, 2015. See "Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for further discussion of these stock repurchase programs.

California Power Markets Litigation Settlement and Avista Foundation Charitable Contribution

On June 23, 2014, Avista Energy (an unregulated indirect subsidiary of Avista Corp.) received $15.0 million in settlement proceeds from the completion of a litigation settlement with various California parties. The litigation was related to the prices paid for power in the California spot markets during the years 2000 and 2001. This resulted in Avista Energy recognizing an increase in pre-tax earnings of approximately $15.0 million, which was recorded as a reduction to other operating expenses within the non-utility operating expenses section of the Consolidated Statements of Income. See "Note 20 of the Notes to the Consolidated Financial Statements" for further information regarding this litigation settlement.

Subsequent to the receipt of the settlement proceeds, we contributed approximately $6.4 million of the proceeds to the Avista Foundation. The remainder of the proceeds were used to fund current operations and decrease reliance on short-term debt.

Liquidity and Capital Resources

During 2014, Avista Corp. received net cash proceeds of $205.4 million from the Ecova sale (prior to tax payments of $74.8 million made in 2014) and we expect to receive additional proceeds of $13.1 million from the escrow accounts related to the sale. We used the funds to pay off $151.5 million owed on our committed line of credit, we paid $79.9 million in a share repurchase program in the second half of 2014 and we initiated a second share repurchase program for the first quarter of 2015.

Avista Corp. has 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 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, 1) there are no default events prior to the requested extension and 2) the remaining term of agreement, including the requested extension period, does not exceed five years. The amendment did not change the amount of the committed line of credit. As of December 31, 2014, there were $105.0 million of cash borrowings and $32.6 million in letters of credit outstanding leaving $262.4 million of available liquidity under this line of credit.

The Avista Corp. 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 December 31, 2014, we were in compliance with this covenant with a ratio of 52.8 percent.

In December 2014, we issued $60.0 million of first mortgage bonds to three institutional investors in a private placement transaction. The first mortgage bonds bear an interest rate of 4.11 percent and mature in 2044.

In 2014, we issued $154.2 million (net of issuance costs) of common stock, which includes $150.1 million associated with the acquisition of AERC and the remainder under the dividend reinvestment and direct stock purchase plan, and employee plans.

With respect to the acquisition of AERC on July 1, 2014 and the subsequent rebalancing of the capital structure at AERC and its primary subsidiary AEL&P, the following transactions occurred:

- Avista Corp. issued 4,501,441 shares of common stock for a total fair value of $150.1 million to acquire AERC.
-

In September 2014, AEL&P issued $75.0 million of 4.54 percent first mortgage bonds due in 2044 to two institutional investors in a private placement transaction. The proceeds from the AEL&P bonds were used to repay approximately $38.0 million of existing AEL&P debt, with the remainder of the proceeds and cash on-hand being paid as a cash dividend of $50.0 million to Avista Corp.

- In December 2014, AERC entered into a 3.85 percent $15.0 million term loan agreement which matures in December 2019. The proceeds from this term loan were paid as a cash dividend to Avista Corp.

In November 2014, AEL&P entered into a committed line of credit in the amount of $25.0 million which expires in November 2019. AEL&P terminated its previous $14.5 million committed line of credit. As of December 31, 2014, there were no borrowings or letters of credit outstanding under this committed line of credit. AEL&P did not borrow under its current or previous committed lines of credit during the second half of 2014.

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The AEL&P committed line of credit agreement contains customary covenants and default provisions including a covenant which does not permit the ratio of “consolidated total debt at AEL&P” to “consolidated total capitalization at AEL&P,” (including the impact of the Snettisham obligation) to be greater than 67.5 percent at any time. As of December 31, 2014, AEL&P was in compliance with this covenant with a ratio of 59.6 percent.

For 2015, we expect to issue approximately $125.0 million of long-term debt in order to maintain an appropriate capital structure and to fund planned capital expenditures.

Through January 31, 2015, we repurchased less common stock through our stock repurchase programs than anticipated. If current market conditions continue through the end of the first quarter, we do not anticipate purchasing any of the 800,000 shares authorized under the first quarter 2015 program. If this occurs, we do not expect to issue any common stock during 2015 other than shares under the employee plans, which we estimate to be approximately $1.2 million.

After considering the expected issuances of long-term debt and common stock during 2015, 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.

Regulatory Matters

General Rate Cases

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

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

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

2012 General Rate Cases

In December 2012, the UTC approved a settlement agreement in Avista Utilities' 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 increased 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 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 provided 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 did not impact our earnings. The ERM balance as of December 31, 2014 was a liability of $14.2 million.

The settlement agreement provided for an authorized return on equity (ROE) 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 were temporary rates, and on January 1, 2015, electric and natural gas base rates were scheduled to revert back to 2013 levels absent any intervening action from

the UTC. The original settlement agreement had a provision that we would not file a general rate case in Washington seeking new rates to take effect before January 1, 2015. In November 2014, the UTC approved a settlement agreement to our Washington general rate cases which were originally filed in February 2014 with rates effective on January 1, 2015 (see further discussion below).

(2) In its Order, the UTC found that much of the approved base rate increase was 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 and $323.9 million for 2013 and 2014 respectively. We expect utility capital expenditures to be about $375 million for 2015 and $350 million in 2016, which are above the capital expenditures contemplated in the settlement agreement.

2014 General Rate Cases

In November 2014, the UTC approved an all-party settlement agreement related to Avista Utilities' electric and natural gas general rate cases filed in February 2014 and new rates became effective on January 1, 2015. The settlement is designed to increase annual electric base revenues by $12.3 million, or 2.5 percent, inclusive of a $5.3 million power supply update as required in the settlement agreement (explained below). The settlement is designed to increase annual natural gas base revenues by $8.5 million, or 5.6 percent.

Expiring and New Rebates and Energy Recovery Mechanism (ERM)

The parties agreed in the settlement that a credit of $8.3 million from the ERM deferral balance will be returned to electric customers to help offset the 2015 rate increase. This ERM balance represents lower net power supply costs in recent years than the costs embedded in base retail rates, which are being returned to customers in the form of a rebate. This rebate will not increase or decrease our net income. Total net deferred power costs under the ERM were a liability of $14.2 million as of December 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.

In addition, our electric customers were receiving benefits from two rebates that expired at the end of 2014 and which reduced monthly energy bills by 2.8 percent during 2014. The parties agreed in the settlement that we will provide a rebate to customers of $8.6 million over an 18 month period related to our sale of renewable energy credits, which will partially replace the expiring rebates and reduce customers’ monthly bills by 1.2 percent, beginning January 1, 2015. The net effect of the expiring rebates and the new rebate will result in an increase of approximately 1.6 percent beginning January 1, 2015. These rebates are passed through to customers and do not increase or decrease our net income.

The overall change in customer billing rates from the approved settlement agreement, including the expiring and new rebates, is 2.5 percent for electric customers and 5.6 percent for natural gas customers effective January 1, 2015.

Power Supply Update and Customer Information and Work Management Systems Deferral

The settlement agreement included a provision that required Avista Utilities to update base power supply costs on November 1, 2014. This update to power supply costs was reflected in the overall electric revenue increase effective January 1, 2015, and reset the base power supply costs for the ERM calculations effective January 1, 2015. The amount of the updated power supply costs was a $5.3 million increase. The increase to customers from the power supply update was offset with the available ERM deferral balance for the calendar year 2015. The use of the ERM deferral balance for the offset will not increase or decrease our net income.

The parties also agreed that the natural gas revenue requirement associated with our investment in the Customer Information and Work Management Systems capital project (Project Compass) for 2015 will be deferred for regulatory purposes for recovery in retail rates through a future general rate case, based on the actual costs of the project at the time it goes into service. Project Compass went into service in February 2015. The net income from the future recovery of these costs and return on investment, estimated to be $2.0 million on a pre-tax basis, will be recognized in the future recovery period.

Decoupling

The parties agreed that Avista Utilities will implement electric and natural gas decoupling mechanisms for a five-year period beginning January 1, 2015. Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. Our actual revenue, based on kilowatt hour and therm sales will vary, up or down, from the level included in a general rate case. This could be due to changes in weather, conservation or the economy. Per the terms of the settlement agreement and the decoupling mechanisms included therein, generally, our electric and natural gas revenues will be adjusted each month to be based on the number of customers, rather than kilowatt hour and therm sales. The difference between revenues based on sales and revenues based on the number of customers will be deferred and either surcharged or rebated to customers beginning in the following year. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations will be made for the prior calendar year. These earnings tests will reflect actual decoupled revenues, normalized power supply costs, and other normalizing adjustments.

- If we have a decoupling rebate balance for the prior year and earn in excess of a 7.32 percent rate of return (ROR), the rebate to customers would be increased by 50 percent of the earnings in excess of the 7.32 percent ROR.
- If we have a decoupling rebate balance for the prior year and earn a 7.32 percent ROR or less, only the base amount of the rebate to customers would be made.
- If we have a decoupling surcharge balance for the prior year and earn in excess of a 7.32 percent ROR, the surcharge to customers would be reduced by 50 percent of the earnings in excess of the 7.32 percent ROR (or eliminated).
- If we have a decoupling surcharge balance for the prior year and earn a 7.32 percent ROR or less, the base amount of the surcharge to customers would be made.

Original Request

Our original request filed with the UTC in February 2014 included a base electric rate increase of 3.8 percent (designed to increase annual electric revenues by $18.2 million). We also requested a base natural gas rate increase of 8.1 percent (designed to increase annual natural gas revenues by $12.1 million). Specific capital structure ratios and the cost of capital components were not agreed to in the settlement agreement, and the revenue increases in the settlement were not tied to the 7.32 percent ROR referenced above. The electric and natural gas revenue increases were negotiated numbers, with each party using its own set of assumptions underlying its agreement to the revenue increases. The parties agreed that the 7.32 percent ROR will be used to calculate the Allowance for Funds Used During Construction (AFUDC) and other purposes.

2015 General Rate Cases

In February 2015, we filed electric and natural gas general rates cases with the UTC. We have requested an overall increase in base electric rates of 6.6 percent (designed to increase annual electric revenues by $33.2 million) and an overall increase in base natural gas rates of 7.0 percent (designed to increase annual natural gas revenues by $12.0 million). Our requests are based on a proposed ROR on rate base of 7.46 percent with a common equity ratio of 48 percent and a 9.9 percent return on equity.

The major driver of these general rate case requests is to recover the costs associated with the ongoing need to maintain, replace and invest in our facilities and equipment. Several significant capital investments we have made and are currently making, that are included in the filing are:

- the ongoing and multi-year redevelopment of the Little Falls hydroelectric plant on the Spokane River,
- the continuing rehabilitation of the Nine Mile hydroelectric plant on the Spokane River,
- information technology upgrades that include the replacement of our customer information and work management systems (which were implemented in February 2015),
- the ongoing project to systematically replace portions of Aldyl-A natural gas distribution pipe, and
- technology investments for deploying Advanced Metering Infrastructure in Washington, including installation of advanced meters, beginning in 2016.

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

Idaho General Rate Cases

2012 General Rate Cases

In March 2013, the IPUC approved a settlement agreement in Avista Utilities' 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 was 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 BPA relating to its prior use of our transmission system was 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 did not impact our net income.

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

The settlement also included 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 share with customers 50 percent of any earnings above the 9.8 percent. In 2013, our returns exceeded this level and we deferred for future ratemaking treatment $3.9 million for Idaho electric customers and $0.4 million for Idaho natural gas customers. Of the electric deferral 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 ratemaking treatment for these deferrals is addressed in the 2014 rate plan extension request explained below. There is no provision for a surcharge to customers if our return on equity is less than 9.8 percent.

In 2014, our returns exceeded a 9.8 percent return on equity and we deferred for future ratemaking treatment $5.6 million for Idaho electric customers, exclusive of the $1.9 million related to 2013 that was recorded in 2014, and $0.2 million for Idaho natural gas customers.

2014 Rate Plan Extension

Avista Utilities did not file new general rate cases in Idaho in 2014, instead, we developed an extension to the 2013 and 2014 rate plan and reached a settlement agreement with all interested parties.

In September 2014, the IPUC approved our settlement, which reflects agreement among all interested parties, for a one-year extension to our current rate plan, which was set to expire on December 31, 2014. Under the approved extension, base retail rates will remain unchanged through December 31, 2015.

The settlement will provide an estimated $3.7 million increase in pre-tax income by reducing planned expenses in 2015 for our Idaho operations, resulting from:

- the delay of the beginning of the amortization of the 2013 previously deferred operations and maintenance costs pertaining to the Colstrip and Coyote Springs 2 thermal generating facilities from 2015 to 2016, and
- deferred accounting, for later review and recovery, of the majority of the costs associated with Project Compass, which was implemented in February 2015.

The settlement agreement establishes an ROE deadband between the currently authorized ROE of 9.8 percent and a 9.5 percent ROE. Under the settlement agreement, we will be allowed to use any 2014 Idaho after-the-fact earnings test deferral (described above under "2012 General Rate Cases") to support an actual earned ROE in 2015 up to 9.5 percent. For 2014, we deferred a total of $7.7 million for the 2014 after-the-fact earnings test, which includes the $1.9 million recorded in 2014 related to the 2013 earnings test. During 2015, if we earn more than the 9.8 percent ROE, 50 percent of the earnings above 9.8 percent will be shared with customers through future ratemaking.

As part of the settlement, we agreed not to file a general rate case in 2014, and would file no earlier than May 31, 2015 for new electric or natural gas base retail rates to become effective on or after January 1, 2016. In addition, the settlement replaced two rebates, which expired on January 1, 2015, that were reducing customers' monthly energy bills by 1.3 percent for electric and 1.7 percent for natural gas. The rebates were replaced for a one-year period, through December 31, 2015, using existing deferral balances due to customers, which will have no impact on our net

income. This provision does not preclude us from filing other rate adjustments such as the PGA.
In addition to the GRCs above, we are evaluating the need to file electric and natural gas GRCs with the IPUC sometime during 2015.

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Oregon General Rate Cases

2013 General Rate Case

In January 2014, the OPUC approved a settlement agreement to Avista Utilities' natural gas general rate case (originally filed in August 2013). As agreed to in the settlement, new rates were 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 $3.8 million). Effective November 1, 2014, rates for Oregon natural gas customers were to 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 was dependent upon the completion of Project Compass and the actual costs incurred through September 30, 2014, and the actual costs incurred through June 30, 2014 related to the Company's Aldyl A distribution pipeline replacement program. As noted elsewhere, Project Compass was completed in February 2015. The November 1, 2014 rate increase was reduced from $1.4 million to $0.3 million due to the delay of Project Compass.

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.

2014 General Rate Case

In January 2015, Avista Utilities filed an all-party settlement agreement with the OPUC related to our natural gas general rate case, which was originally filed in September 2014. The settlement agreement was designed to increase base natural gas revenues by 6.1 percent or $6.1 million. This base rate increase was offset by $0.3 million for a separate rate adjustment that we are already receiving from customers and it was offset by a $0.8 million credit to customers related to having an early implementation date for the revenue increase (prior to the full 10 months allowed in Oregon for the OPUC to make a decision on the case and new rates to take effect). The net increase to revenue after the two offsets was $5.0 million. The parties to the settlement had requested a decision by the OPUC prior to March 1, 2015, such that new retail rates could be effective on March 1, 2015.

This settlement agreement provided for an overall authorized rate of return of 7.52 percent with a common equity ratio of 51 percent and a 9.5 percent return on equity.

The original request was for an overall increase in base natural gas rates of 9.3 percent (designed to increase annual natural gas revenues by $9.1 million) and it was based on a proposed rate of return of 7.77 percent with a common equity ratio of 51 percent and a 9.9 percent return on equity.

On February 23, 2015, the OPUC issued an order rejecting the all-party settlement agreement filed with the OPUC by the parties on January 21, 2015. The OPUC expressed concerns related to three issues: 1) the proposed early rate implementation credit; 2) the combination of proposed rate increases and rate decreases across the customer classes (rate spread); and 3) the customer count tracking mechanism. With regard to the early rate implementation credit, the order stated, among other things, that there was no evidence in the record that explains the derivation of the rate credit amount, or why the credit would be applied to all customer classes. On rate spread, the OPUC’s order expressed concern about proposed increases to rates for some customer classes, and decreases for other customer classes, absent more compelling evidence. And finally, the OPUC expressed concern that the customer count tracking mechanism is contrary to standard ratemaking.

The OPUC’s order directed the Administrative Law Judge to convene a prehearing conference to schedule further proceedings in a manner that will allow for the timely completion of the case. The OPUC’s order also encouraged the parties to come back with a partial stipulation that encompasses these issues. Furthermore, the OPUC stated that its order does not preclude the parties from reaching a global settlement of all issues that addresses the concerns identified by the OPUC.

In addition to the GRCs above, we are evaluating the need to file a natural gas GRC with the OPUC sometime during 2015.

Alaska General Rate Case

AEL&P's last GRC was filed in 2010 and approved by the RCA in 2011.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

In May 2013, the UTC approved Avista Utilities' 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 BPA, whereby the BPA reimbursed us $11.7 million in the first quarter of 2013 for the BPA's past use of our transmission system. The second issue related to $4.3 million of costs we incurred for the development of a wind generation project site near Reardan, Washington, which was 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 were allocable to our Washington business, leaving $5.1 million which was 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 separately tracked and deferred 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) was 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 Avista Utilities' 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 $3.9 million as of December 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 2012, 2013 and 2014:

Jurisdiction	PGA Effective Date	Percentage Increase / (Decrease) in Billed Rates
Washington	March 1, 2012	(6.4)%
	November 1, 2012	(4.4)%
	November 1, 2013	9.2%
	November 1, 2014	1.2%
Idaho	March 1, 2012	(6.0)%
	October 1, 2012	(3.1)%
	October 1, 2013	7.5%
	November 1, 2014	(2.1)%
Oregon	November 1, 2012 [1]	(7.5)%
	January 1, 2013 [1]	(0.8)%
	November 1, 2013	(7.9)%
	November 1, 2014	8.3%

(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 Avista Utilities' 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 $14.2 million as of December 31, 2014 compared to $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 existing ERM deferral balance to reduce the net average electric rate increase impact to customers in 2013. Additionally, during 2014 there was 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,

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- the level and availability of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices), and
- retail loads.

Under the ERM, Avista Utilities absorbs the cost or receives 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 $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 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, Avista Utilities makes 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 the filing, the staff reviewed the prudence of the Colstrip outage from July 2013 through January 2014. UTC staff found no imprudence by Avista Corp. related to the Colstrip outage and recommended approval of all the ERM related transactions for 2013. 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. The 2013 ERM deferred power costs transactions were approved by an order from the UTC.

Avista Utilities has 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 $8.3 million as of December 31, 2014 compared to an asset of $5.1 million as of December 31, 2013.

Results of Operations - Overall

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

As discussed in "Item 7. Management's Discussion and Analysis: Executive Level Summary," Ecova was disposed of as of June 30, 2014. As a result, in accordance with Generally Accepted Accounting Principles (GAAP), all of Ecova's operating results were removed from each line item on the Consolidated Statements of Income and reclassified into discontinued operations for all periods presented. The discussion of continuing operations below does not include any

Ecova amounts. For our discussion of discontinued operations and Ecova, see "Item 7. Management's Discussion and Analysis: Ecova - Discontinued Operations."

The balances included below for utility operations reconcile to the Consolidated Statements of Income. Beginning on July 1, 2014, AEL&P is included in the overall utility results.

2014 compared to 2013

Utility revenues increased $31.1 million, after elimination of intracompany revenues (within Avista Utilities) of $142.2 million for 2014 and $151.9 million for 2013. Avista Utilities' portion of utility revenues increased $9.5 million and AEL&P had electric revenues of $21.6 million, representing its revenues for the six months ended December 31, 2014. Including intracompany revenues, Avista Utilities' electric revenues decreased $31.6 million and natural gas revenues increased $31.4 million. Total retail electric revenues increased $14.8 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. This was partially offset by a decrease in retail sales volumes. Wholesale electric revenues increased $10.6 million due to an increase in sales prices partially offset by a decrease in sales volumes, while sales of fuel decreased $42.9 million. Other electric revenues decreased $8.6 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. In 2014, we estimated a provision for earnings sharing of $7.5 million for Idaho electric customers with $5.6 million representing our estimate for 2014 and $1.9 million representing an adjustment of our 2013 estimate. In 2013, we recorded a provision for earnings sharing of $2.0 million for Idaho electric customers. Retail natural gas revenues decreased $1.3 million due to a decrease in volumes caused by warmer than normal weather during the fourth quarter, partially offset by an increase in retail rates. Wholesale natural gas revenues increased $33.5 million due to an increase in prices and volumes.

Utility resource costs decreased $11.3 million, after elimination of intracompany resource costs of $142.2 million for 2014 and $151.9 million for 2013. Avista Utilities' portion of resource costs decreased $17.2 million and this was offset by utility resource costs at AEL&P of $5.9 million, representing its resource costs for the six months ended December 31, 2014. Including intracompany resource costs, Avista Utilities' electric resource costs decreased $57.7 million and natural gas resource costs increased $30.7 million. The decrease in Avista Utilities' electric resource costs was due to the Colstrip outage in 2013 and increased hydroelectric generation in 2014. Specifically, there were decreases in purchased power, fuel for generation and 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). 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 $10.6 million and was partially the result of AEL&P being included for the six months ended December 31, 2014, which added $5.9 million to other operating expenses. Avista Utilities incurred increased generation, transmission and distribution operating and maintenance expenses and increased outside services. There were also transaction fees associated with the AERC acquisition of $1.3 million in 2014 compared to $1.6 million in 2013. These were partially offset by a decrease in pension and other post-retirement benefits expense.

Utility depreciation and amortization increased $12.4 million driven by additions to utility plant and the inclusion of $2.6 million related to AEL&P for the second half of the year.

Taxes other than income taxes increased $5.9 million primarily due to increased production, distribution and transmission property taxes. Also, 2014 included $1.1 million related to AEL&P for the second half of the year.

Other non-utility operating expenses decreased $8.2 million primarily due to the receipt of $15.0 million related to the settlement of the California power markets litigation (which was recorded as a reduction to operating expenses), partially offset by a $6.4 million contribution to the Avista Foundation.

Interest expense decreased $1.8 million primarily due to the long-term debt outstanding during 2014 having a lower interest rate than the long-term debt outstanding during 2013. This includes recent issuances at low interest rates. This was partially offset by the acquisition of AERC, which added $1.4 million for the second half of 2014.

Other income-net increased $6.2 million primarily due to net income from investments of $0.3 million compared to net losses of $3.4 million in 2013. The net losses in 2013 were the result of impairment losses associated with our investment in an energy storage company and our investment in a fuel cell business. There was also an increase in equity-related AFUDC of $2.7 million during 2014.

Income taxes increased $14.2 million and our effective tax rate was 37.6 percent for 2014 compared to 35.7 percent for 2013. The increase in expense was primarily due to an increase in income before income taxes. The increase in the effective tax rate was primarily the result of the Section 199 Domestic Manufacturing Deduction not being available to the Company due to limitations on taxable qualified production activities income.

2013 compared to 2012

Utility revenues increased $49.8 million, after elimination of intracompany revenues of $151.9 million for 2013 and $88.2 million for 2012. Including intracompany revenues, electric revenues increased $62.4 million and natural gas revenues increased $51.1 million. Total retail electric revenues increased $13.8 million due to general rate increases and an increase in volumes sold, which was primarily the result of warmer than normal weather during the cooling season and colder than normal weather during the fourth quarter heating season. Wholesale electric revenues increased $24.8 million and sales of fuel increased $10.8 million. Other electric revenues increased $15.0 million primarily due to the receipt of revenue from the BPA for past use of our electric transmission system. Retail natural gas revenues increased $13.3 million due to an increase in volumes caused by colder than normal weather during the fourth quarter, partially offset by a decrease in retail rates. Wholesale natural gas revenues increased $36.1 million due to an increase in prices, partially offset by a decrease in volumes.

Utility resource costs decreased $3.5 million, after elimination of intracompany resource costs of $151.9 million for 2013 and $88.2 million for 2012. Including intracompany resource costs, electric resource costs increased $24.8 million and natural gas

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resource costs increased $35.4 million. The increase in electric resource costs was primarily due to an increase in fuel costs (due to higher natural gas generation and higher natural gas fuel prices), 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 the write-off of $2.5 million of Reardan project costs that are allocable to our Washington business. The increase in natural gas resource costs was primarily due to an increase in natural gas prices, partially offset by a decrease in volumes (primarily attributable to wholesale sales).

Utility other operating expenses decreased $0.6 million primarily as a result of a decrease in administrative and general labor expenses (which included $7.3 million of costs to implement the voluntary severance incentive plan in 2012 only) and a decrease in generation maintenance expenses. These decreases were partially offset by increases in pension and other postretirement benefit expenses and electric, production and gas distribution related operating and maintenance expenses.

Utility depreciation and amortization increased $5.1 million driven by additions to utility plant.

Taxes other than income taxes increased $5.0 million primarily due to increased franchise, municipal, and property related taxes.

Interest expense increased $2.0 million primarily due to the issuance of long-term debt in November 2012 that increased the amount of long-term debt outstanding.

Capitalized interest increased $1.3 million primarily due to higher average construction work in progress balances.

Other income-net increased $2.5 million primarily due to an increase in equity-related AFUDC of $2.0 million. In addition, during 2013 we incurred impairment losses of $3.4 million ($2.2 million after-tax) associated with our investment in an energy storage company and our investment in a fuel cell business. During 2012, we incurred total losses on investments of $3.3 million, which included impairment losses of $2.4 million ($1.5 million after-tax) related to our investment in a fuel cell business and the write-off of our investment in a solar energy company.

Income taxes increased $18.3 million and our effective tax rate was 35.7 percent for 2013 compared to 34.1 percent for 2012. The increase in expense was primarily due to an increase in income before income taxes. The change in the effective tax rate was primarily related to a reduction in the amount of our pension contribution deduction.

Results of Operations - 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 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.

2014 compared to 2013

Net income for Avista Utilities was $113.3 million for 2014, an increase from $108.6 million for 2013. Avista Utilities’ income from operations was $240.0 million for 2014 compared to $232.6 million for 2013. Earnings at Avista Utilities increased primarily due to the implementation of general rate increases, lower net power supply costs and a decrease in interest expense. These were partially offset by a provision for earnings sharing in Idaho, and 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 year ended December 31 (dollars in thousands):

	Electric		Natural Gas		Intracompany		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
Operating revenues	$998,988	$1,030,606	$556,664	$525,259	$(142,153)	$(151,870)	$1,413,499	$1,403,995
Resource costs	418,541	476,226	395,956	365,230	(142,153)	(151,870)	672,344	689,586
Gross margin	$580,447	$554,380	$160,708	$160,029	$—	$—	$741,155	$714,409

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Avista Utilities' operating revenues increased $9.5 million and resource costs decreased $17.2 million, which resulted in an increase of $26.7 million in gross margin. The gross margin on electric sales increased $26.0 million and the gross margin on natural gas sales increased $0.7 million. The increase in electric gross margin was primarily due to general rate increases in Washington and Idaho and lower net power supply costs (due to the Colstrip outage in 2013 and increased hydroelectric generation in 2014). This was partially offset by a $7.5 million provision for earnings sharing in Idaho in 2014, compared to $2.0 million in 2013. For 2014, we recognized a pre-tax benefit of $5.4 million under the ERM in Washington compared to a pre-tax expense of $4.7 million for 2013. This change represents a decrease in net power supply costs due to the Colstrip outage in 2013 and increased hydroelectric generation in 2014. Electric gross margin for 2013 included the net benefit from the settlement with the BPA of $5.1 million. The increase in natural gas gross margin was primarily due to general rates increases, mostly offset by warmer weather during the fourth quarter of 2014.

Intracompany revenues and resource costs represent purchases and sales of natural gas between our natural gas distribution operations and our electric generation operations (as fuel for our generation plants). These transactions are eliminated in the presentation of total results for Avista Utilities and in the consolidated financial statements but are 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 year ended December 31 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2014	2013	2014	2013
Residential	$338,697	$331,867	3,694	3,745
Commercial	300,109	289,604	3,189	3,147