AVISTA CORP
Form 10-K
February 28, 2012
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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, 2011

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	**(I.R.S. Employer**

incorporation or organization)	**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 $1,489,452,508 based on the last reported sale price thereof on the consolidated tape on June 30, 2011.

As of January 31, 2012, 58,554,301 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 10, 2012	**Part III, Items 10, 11, 12, 13 and 14**

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* = not an applicable item in the 2011 calendar year for Avista Corporation

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ACRONYMS AND TERMS

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

Acronym/Term	Meaning
aMW	- Average Megawatt - a measure of the average rate at which a particular generating source produces energy over a period of time
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
Avista Utilities	- Operating division of Avista Corp. 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 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 Energy Recovery Mechanism 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)
DOE	- The state of Washington s Department of Ecology
Ecos	- A Portland, Oregon-based energy efficiency solutions provider acquired by Ecova in 2009
Ecova	- Formerly known as Advantage IQ, Inc. (Advantage IQ), provider of facility information and cost management services for multi-site customers throughout North America, subsidiary of Avista Capital
Energy	- The amount of electricity produced or consumed over a period of time, measured in KWH or MWH

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EPA	- Environmental Protection Agency
ERM	- The Energy Recovery Mechanism in the state of Washington
FASB	- Financial Accounting Standards Board
FERC	- Federal Energy Regulatory Commission
GHG	- Greenhouse gas
IPUC	- Idaho Public Utilities Commission
IRP	- Integrated Resource Plan
Jackson Prairie	- Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington
kV	- Kilovolt or 1000 volts, a measure of capacity on transmission lines
KW, KWH	- Kilowatt or 1000 watts a measure of generating output, kilowatt-hour or 1000 watt hours a measure of energy produced
Lancaster Plant	- A natural gas-fired combined cycle combustion turbine plant located in Idaho
MW, MWH	- Megawatt or 1000 KW, megawatt-hour or 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 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
RTO	- Regional Transmission Organization
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)
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
WUTC	- Washington Utilities and Transportation Commission

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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, 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, p expressions. 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. Many of these factors are beyond our control and they could have a significant effect on our operations, results of operations, financial condition or cash flows. This 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) and their effects on energy demand and electric generation, including the effect of precipitation and temperatures on the availability of hydroelectric resources, the effect of wind patterns on the availability of wind resources, the effect of temperatures on customer demand, and similar impacts on supply and demand in the wholesale energy markets;
- the effect of state and federal regulatory decisions on our ability to recover costs and earn a reasonable return including, but not limited to, the disallowance of costs and investments, and delay in the recovery of capital investments and operating costs;

changes in wholesale energy prices that can affect, among other things, the cash requirements to purchase electricity and natural gas, the value received for sales in the wholesale energy market, the necessity to request changes in rates that are subject to regulatory approval, 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 effect on the demand for, and customers payment for, our utility services;

global financial and economic conditions (including the impact on capital markets) and their effect on our ability to obtain funding at a reasonable cost;

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;

the potential effects of legislation or administrative rulemaking, including the possible adoption of national or state laws requiring our resources to meet certain standards and placing restrictions on greenhouse gas emissions to mitigate concerns over global climate changes;

changes in actuarial assumptions, interest rates and the actual return on plan assets for our pension plan, which can affect future funding obligations, pension expense and pension plan liabilities;

volatility and illiquidity in wholesale energy markets, including the availability of willing buyers and sellers, and prices of purchased energy and demand for energy sales;

unplanned outages at any of our generating facilities or the inability of facilities to operate as intended;

the outcome of pending regulatory and legal proceedings arising out of the western energy crisis of 2000 and 2001, including possible refunds;

the outcome of legal proceedings and other contingencies;

changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;

wholesale and retail competition including, but not limited to, alternative energy sources, suppliers and delivery arrangements;

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the ability to comply with the terms of the licenses for our hydroelectric generating facilities at cost-effective levels;

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, or mechanical breakdowns that may occur while operating and maintaining our generation, transmission and distribution systems;

blackouts or disruptions of interconnected transmission systems;

disruption to information systems, automated controls and other technologies that we rely on for operations, communications and customer service;

the potential for terrorist attacks, cyber security attacks or other malicious acts, that cause damage to our utility assets, as well as the national economy in general; including the impact of acts of terrorism, cyber security attacks or vandalism that damage or disrupt information technology systems;

delays or changes in construction costs, and/or our ability to obtain required permits and materials for present or prospective facilities;

changes in the long-term climate of the Pacific Northwest, 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 the loss of significant customers;

the loss of key suppliers for materials or services;

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 and counterparties;

the effect of any potential decline in our credit ratings, including impeded access to capital markets, higher interest costs, and certain covenants with ratings triggers in our financing arrangements and wholesale energy contracts;

- increasing health care costs and the resulting effect on health insurance provided to our employees and retirees;
- increasing costs of insurance, more restricted coverage terms and our ability to obtain insurance;
- work force issues, including changes in collective bargaining unit agreements, strikes, work stoppages or 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, among other things, costly litigation and 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 the payment acceptance policies of Ecova s client vendors that could reduce operating revenues;
- potential difficulties for Ecova in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities; and
- changes in our strategic business plans, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses.

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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PART I

Item 1. Business

Company Overview

Avista Corporation (Avista Corp. or the Company), incorporated in the state of Washington in 1889, is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. As of December 31, 2011, we employed 1,594 people in our utility operations and 1,215 people in our subsidiary businesses. Our corporate headquarters are in Spokane, Washington, the second-largest city in Washington state. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region. Of all the forces that have shaped the Spokane County economy, none is more significant than Spokane s historic role as a regional center of services for the surrounding rural populations of 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 but is separate from our service area in southwest Oregon.

We have two reportable business segments as follows:

- **Avista Utilities** an operating division of Avista Corp. that comprises our regulated utility operations. Avista Utilities generates, transmits and distributes electricity and distributes natural gas. The utility also engages in wholesale purchases and sales of electricity and natural gas.

- **Ecova (formerly known as Advantage IQ)** an indirect subsidiary of Avista Corp. (79.2 percent owned as of December 31, 2011) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova s primary product lines include expense management services for utility and telecom needs as well as strategic energy management and efficiency services that include procurement, conservation, performance reporting, financial planning and energy efficiency program management for commercial enterprises and utilities.

We have other businesses, including a sheet metal fabrication business, emerging technology venture fund investments and commercial real estate investments, as well as Spokane Energy, LLC (Spokane Energy). These activities do not represent a reportable business segment and are conducted by various indirect subsidiaries of Avista Corp.

Ecova and various other companies are subsidiaries of Avista Capital, Inc. (Avista Capital) which is a direct, wholly owned subsidiary of Avista Corp. Total Avista Corp. stockholders equity was $1,185.7 million as of December 31, 2011, of which $72.0 million represented our investment in Avista Capital.

See Item 6. Selected Financial Data and Note 24 of the Notes to Consolidated Financial Statements for information with respect to the operating performance of each business segment (and other subsidiaries).

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Avista Utilities

General

Through our regulated utility operations, we generate, transmit and distribute electricity and distribute natural gas. 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.

Our utility 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 northeast and southwest Oregon. At the end of 2011, we supplied retail electric service to 360,000 customers and retail natural gas service to 321,000 customers across our entire service territory. Our service territory covers 30,000 square miles with a population of 1.5 million. 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, we generate electricity from facilities that we own and we purchase capacity and 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 our 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 sell and purchase electric capacity and energy and fuel in wholesale markets as part of the process of acquiring and balancing resources to serve our load obligations. These transactions range from terms of 30 minutes up to multiple years. We make continuing projections of:

- electric loads at various points in time (ranging from 30 minutes 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 and fuel to match expected resources to expected electric load requirements. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

- purchasing fuel for generation,
- when economical, selling fuel and substituting wholesale electric purchases, and

other wholesale transactions to capture the value of generation and transmission resources and fuel delivery capacity contracts. Our optimization process includes entering into hedging transactions to manage risks.

Our 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 $13.8 million in 2011, $12.8 million in 2010 and $9.3 million in 2009.

Electric Requirements

Our peak electric native load requirement for 2011 occurred on January 11, 2011 at which time our total obligation was 2,381 MW consisting of:

- native load of 1,669 MW,
- long-term wholesale obligations of 243 MW, and
- short-term wholesale obligations of 469 MW.

At that time our maximum resource capacity available was 2,923 MW, which included:

- company-owned or controlled electric generation of 1,756 MW,
- long-term hydroelectric contracts with certain Public Utility Districts (PUDs) of 124 MW,
- long-term thermal generation contract with Lancaster Plant of 279 MW,

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other long-term wholesale contracts of 189 MW, and

short-term wholesale purchases of 575 MW.

Electric Resources

We have a diverse electric resource mix of hydroelectric projects, thermal generating facilities, and power purchases and exchanges.

At the end of 2011, our facilities had a total net capability of 1,791 MW, of which 56 percent was hydroelectric and 44 percent was thermal. See Item 2. Properties for detailed information on generating facilities.

Hydroelectric Resources We own and operate 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 2012 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 542 average megawatts (aMW) (or 4.76 million MWhs). Hydroelectric resources provided 637 aMW for 2011, 476 aMW for 2010 and 526 aMW for 2009.

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

	2011	2010	2009
Noxon Rapids	2,110	1,503	1,673
Cabinet Gorge	1,292	942	1,061
Post Falls	90	90	84
Upper Falls	73	71	52
Monroe Street	110	106	104
Nine Mile	90	101	106
Long Lake	556	480	487
Little Falls	213	201	199
Total company-owned hydroelectric generation	4,534	3,494	3,766
Long-term hydroelectric contracts with PUDs	1,047	685	839
Total hydroelectric generation	5,581	4,179	4,605

Thermal Resources We own:

the combined cycle combustion turbine (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 northeast 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 unilateral 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.

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

	2011	2010	2009
Coyote Springs 2	705	1,661	1,559
Colstrip	1,433	1,749	1,277
Kettle Falls GS	291	312	184
Northeast CT and Rathdrum CT	8	12	44
Boulder Park and Kettle Falls CT	10	14	33
Total company-owned thermal generation	2,447	3,748	3,097
Long-term contract with Lancaster Plant	835	1,410	
Total thermal generation	3,282	5,158	3,097

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 In June 2011, we entered into a 30-year PPA with Palouse Wind, LLC (Palouse Wind), an affiliate of First Wind Holdings, LLC. Under the PPA, we will acquire all of the power and renewable attributes produced by a wind project being developed by Palouse Wind in Whitman County, Washington. The wind project is expected to have a nameplate capacity of approximately 105 MW and produce approximately 40 aMW with deliveries by the end of 2012. We decided to enter this PPA due, in part, to market changes reducing the cost of renewable resource projects. This was due, in part, to tax incentives for the construction of renewable resource projects that remain in effect through 2012. The power purchased from Palouse Wind will help to meet our Washington renewable energy requirements beginning in 2016, as well as provide a new energy resource to serve our system retail load requirements. Under the PPA, we have the option to purchase the wind project each year following the 10th anniversary of the commercial operation date at a price determined under the contract.

Other Purchases, Exchanges and Sales We purchase and sell power under various long-term contracts. We also enter into short-term purchases and sales. See Electric Operations for additional information with respect to the use of wholesale purchases and sales as part of our resource optimization process.

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 WUTC and the IPUC. Existing 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 2011, 2010 and 2009.

Hydroelectric Licensing

We are a licensee under the Federal Power Act as administered by the FERC, which includes regulation of hydroelectric generation resources. Except for the Little Falls Plant, all of our hydroelectric plants are regulated by the FERC through project licenses. The licensed projects are subject to the provisions of Part I of the Federal Power Act. 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.

The Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) and the Noxon Rapids Hydroelectric Generating Project (Noxon Rapids) are under one 45-year FERC license issued in March 2001. As part of the Clark Fork Settlement Agreement, we initiated the implementation of protection, mitigation and enhancement measures in March 1999. Measures in the agreement address issues related to fisheries, water quality, wildlife, recreation, land use, cultural resources and erosion.

See Cabinet Gorge Total Dissolved Gas Abatement Plan in Note 21 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 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 21 of the Notes to Consolidated Financial Statements.

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Future Resource Needs

We have 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 over 30 minute, hourly, daily, monthly and annual durations, which vary widely because of the factors that influence demand. Our average hourly load was 1,095 aMW in 2011, 1,075 aMW in 2010 and 1,082 aMW in 2009. The following is a forecast of our average annual energy requirements and resources for 2012, 2013, 2014 and 2015:

Forecasted Electric Energy Requirements and Resources

(aMW)

	2012	2013	2014	2015
Requirements:				
System load	1,113	1,134	1,150	1,165
Contracts for power sales	140	127	109	58
Total requirements	1,253	1,261	1,259	1,223
Resources:				
Company-owned and contract hydro generation (1)	542	525	527	495
Company-owned base load thermal generation (2)	511	503	507	511
Contracts for power purchases	399	440	436	432
Total resources	1,452	1,468	1,470	1,438
Surplus resources	199	207	211	215
Additional available energy (3)	152	153	153	139
Total surplus resources	351	360	364	354

(1) The forecast assumes near normal hydroelectric generation (decline in 2013 and 2015 is due to changes in contracts with PUDs).

(2) Excludes the Northeast CT and Rathdrum CT. We generally use our thermal resources to meet electric load requirements due to either below normal hydroelectric generation or increased loads or outages at other generating facilities, and/or when operating costs are lower than short-term wholesale market prices.

(3) Northeast CT and Rathdrum CT. The combined maximum capacity of the Northeast CT and Rathdrum CT is 243 MW, with estimated available energy production as indicated for each year.

In August 2011, we filed our 2011 Electric Integrated Resource Plan (IRP) with the WUTC and the IPUC. We are required to file an IRP every two years. 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 2011 IRP include:

- A contract for the 105 MW Palouse Wind, LLC project, which is expected to help meet the requirements of the Washington state Energy Independence Act beginning in 2016, as well as provide a new resource to serve our customers increasing energy needs.

- An additional 42 aMW of wind or qualifying renewable resource or energy credits are required under the same Act beginning in 2021.

- Energy efficiency measures are expected to save 310 aMW of cumulative energy over the 20-year IRP timeframe. This aggressive effort could reduce load growth to half of what it would be without these measures.

- 750 MW of new natural gas-fired generation facilities are required between 2018 and 2031.

- Three grid modernization programs are projected to save 5 aMW of energy by 2013.

- 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 subject to the Washington state Energy Independence Act, which includes renewable energy portfolio standards and we must obtain a portion of our electricity from qualifying renewable resources or through purchase of renewable energy credits. Future generation resource decisions will be impacted by legislation for restrictions on greenhouse gas 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.

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Natural Gas Operations

General We provide natural gas distribution services to retail customers in parts of eastern Washington, northern Idaho, and parts of northeast and southwest Oregon.

Market prices for natural gas, like other commodities, can be volatile. To provide reliable supply and to manage the impact of volatile prices on our customers, we procure natural gas through a diversified mix of spot market purchases and forward fixed price purchases from various supply basins and over various time periods. We also use natural gas storage capacity to support high demand periods and to procure natural gas when prices may be seasonally lower. Securing prices throughout the year and even into subsequent years mitigates potential adverse impacts of significant purchase requirements in a volatile price environment.

Like prices, natural gas loads can also be volatile. Daily natural gas loads can differ significantly from the monthly 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 significant portion of our 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 immediately upcoming natural gas operating year (November through October). We also leave a significant portion of our natural gas supply requirements unhedged for purchase in short-term and spot markets.

As part of the process of balancing natural gas retail load requirements with resources, we engage in wholesale purchases and sales of natural gas. We plan for sufficient natural gas delivery capacity to serve our retail customers on a theoretical peak day. As such, we generally have more pipeline and storage capacity than what is needed. We optimize natural gas resources by using excess resources and market opportunities to generate economic value that offsets net natural gas 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.

We also provide transportation service to certain large commercial and industrial natural gas customers who purchase natural gas through third-party marketers. For these customers, we move their natural gas through our distribution system from natural gas transmission pipeline delivery points to the customers premises.

Natural Gas Supply We purchase all of our natural gas in wholesale markets. We are connected to multiple supply basins in the western United States and western Canada through firm capacity delivery rights on six 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. We have interstate pipeline capacity to serve approximately 25 percent of natural gas supplies from domestic sources, with the remaining 75 percent from Canadian sources. Natural gas prices in the Pacific Northwest are affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada. Future prices and delivery constraints may cause our source mix to vary.

Natural Gas Storage We own a one-third interest in the Jackson Prairie Natural Gas Storage Project (Jackson Prairie), an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 11.5 million therms, with a total working natural gas capacity of 253 million therms.

Avista Utilities gained 30.3 million therms of additional capacity at Jackson Prairie on May 1, 2011 for use in its utility operations. This capacity was originally held by Avista Energy and as part of the asset sales agreement this capacity had been assigned to Shell Energy through April 30, 2011.

Natural gas storage enables us to place natural gas into storage when prices may be lower or to satisfy minimum natural gas purchasing requirements, as well as to meet high demand periods or to withdraw natural gas from storage when spot prices are higher.

Regulatory Issues

General As a regulated public utility, we are 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 WUTC, the IPUC, the Public Utility Commission of Oregon (OPUC), and the Public Service Commission of the State of Montana (Montana Commission). Approval of the issuance of securities is not required from the Montana Commission. We are also subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales.

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 determined on a cost of service basis.

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Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for us to 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. In general, a request for new rates in Washington and Idaho is made on the basis of net investment as of a date, and operating expenses and revenues for a test period ended, prior to the date of the request. Our retail revenues are derived from the number of units of electricity or natural gas actually sold and rates are based on the assumption that sales of electricity and natural gas will be the same as during the test period. Although the current ratemaking process in these states provides recovery of some future changes in net investment, operating costs and revenues, it does not reflect all changes in costs for the period in which new retail rates will be in place. This historically has resulted in a lag between the time we incur costs and the time when we start recovering the costs through subsequent changes in rates. Oregon currently allows a forecasted test year, which generally is more effective in providing timely recovery of costs.

In Washington, there is currently a proposal for an electric decoupling mechanism. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Avista Utilities Regulatory Matters Proposed Electric Decoupling Washington for further information.

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 23 of the Notes to Consolidated Financial Statements for additional information about regulation, depreciation and deferred income taxes.

General Rate Cases We regularly review 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 We defer 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 WUTC 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 23 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 respective state, we are allowed to adjust natural gas rates periodically (with regulatory approval) to reflect increases or decreases in the cost of natural gas purchased. Differences between actual natural gas costs and the natural gas costs included in retail rates are deferred and charged or credited to expense when regulators approve inclusion of the cost changes in rates. We typically propose such adjustments at least once per year. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Avista Utilities Regulatory Matters Purchased Gas Adjustments and Note 23 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) and other entities may participate in the development of independent electric generating plants for sales to wholesale customers.

Public utilities operating under the Federal Power Act 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.

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Regional Transmission Organizations

Beginning with FERC Orders No. 888 and No. 2000 (issued in 2000) and continuing with subsequent rulemakings and policies (including the Variable Energy Resource Notice of Proposed Rulemaking), 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) such as an independent system operator (ISO). While it has not mandated RTO formation, the FERC has issued orders and made public policy statements indicating its support for the development and formation of independent organizations, including those intended to implement a number of regional transmission planning coordination requirements.

We have participated in discussions with transmission providers and other stakeholders in the Pacific Northwest for several years regarding the possible formation of an ISO in the region. We ultimately became a member of ColumbiaGrid, a Washington nonprofit membership corporation with an independent slate of directors formed to improve the operational efficiency, reliability, and planned expansion of the transmission grid in the Pacific Northwest. ColumbiaGrid is not an ISO, but performs limited functions as set forth in specific agreements with ColumbiaGrid members and other stakeholders. ColumbiaGrid and its members also work with other western organizations to address operational efficiencies, including WestConnect and the Northern Tier Transmission Group. 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.

The FERC requires RTOs to provide various data and is currently requesting non-RTO regions to report similar data for the purpose of establishing performance metrics. We expect the FERC to use this data to compare RTO and non-RTO regions. We cannot foresee what policy objectives the FERC may develop as a result of establishing such performance metrics.

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 fines for non-compliance with these standards and other FERC regulations.

The FERC certified the North American Electricity Reliability Corporation (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 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.

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AVISTA UTILITIES OPERATING STATISTICS

	Years Ended December 31, 2011	2010	2009
ELECTRIC OPERATIONS			
ELECTRIC OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 324,835	$ 296,627	$ 315,649
Commercial	280,139	265,219	273,954
Industrial	122,560	114,792	107,741
Public street and highway lighting	6,941	6,702	6,607
Total retail	734,475	683,340	703,951
Wholesale	78,305	165,553	88,414
Sales of fuel	153,470	106,375	32,992
Other	21,937	19,015	15,426
Total electric operating revenues	$ 988,187	$ 974,283	$ 840,783
ELECTRIC ENERGY SALES (Thousands of MWhs):			
Residential	3,728	3,618	3,791
Commercial	3,122	3,100	3,177
Industrial	2,147	2,099	1,948
Public street and highway lighting	26	26	26
Total retail	9,023	8,843	8,942
Wholesale	2,796	3,803	2,354
Total electric energy sales	11,819	12,646	11,296
ELECTRIC ENERGY RESOURCES (Thousands of MWhs):			
Hydro generation (from Company facilities)	4,534	3,494	3,766
Thermal generation (from Company facilities)	2,447	3,748	3,097
Purchased power - hydro generation from long-term contracts with PUDs	1,047	685	839
Purchased power - wholesale	4,388	5,315	4,152
Power exchanges	(24)	(15)	(18)
Total power resources	12,392	13,227	11,836
Energy losses and Company use	(573)	(581)	(540)
Total energy resources (net of losses)	11,819	12,646	11,296
NUMBER OF ELECTRIC RETAIL CUSTOMERS (Average for Period):			
Residential	316,762	315,283	313,884
Commercial	39,618	39,489	39,276
Industrial	1,380	1,376	1,394
Public street and highway lighting	455	449	444

Total electric retail customers	358,215	356,597	354,998
ELECTRIC RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh)	11,769	11,476	12,079
Revenue per KWh (in cents)	8.71	8.20	8.33
Annual revenue per customer	$ 1,025.48	$ 940.83	$ 1,005.62
ELECTRIC AVERAGE HOURLY LOAD (aMW)	1,096	1,075	1,082
RESOURCE AVAILABILITY at time of system peak (MW):			
Total requirements (winter):			
Retail native load	1,669	1,704	1,763
Wholesale obligations	712	803	608
Total requirements (winter)	2,381	2,507	2,371
Total resource availability (winter)	2,923	2,905	2,514
Total requirements (summer):			
Retail native load	1,535	1,556	1,522
Wholesale obligations	472	822	685
Total requirements (summer)	2,007	2,378	2,207
Total resource availability (summer)	2,370	2,662	2,499
COOLING DEGREE DAYS: (1)			
Spokane, WA			
Actual	426	380	589
30-year average	434	434	394
% of average	98%	88%	149%

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

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AVISTA UTILITIES OPERATING STATISTICS

	Years Ended December 31, 2011	2010	2009
NATURAL GAS OPERATIONS			
NATURAL GAS OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 219,557	$ 193,169	$ 251,022
Commercial	111,964	98,257	135,236
Industrial and interruptible	6,699	6,494	9,945
Total retail	338,220	297,920	396,203
Wholesale	195,882	197,364	143,524
Transportation	6,709	6,470	6,067
Other	7,414	9,495	8,624
Total natural gas operating revenues	$ 548,225	$ 511,249	$ 554,418
THERMS DELIVERED (Thousands of Therms):			
Residential	207,202	188,546	207,979
Commercial	125,344	113,422	126,345
Industrial and interruptible	10,157	9,755	10,918
Total retail	342,703	311,723	345,242
Wholesale	510,755	468,887	397,977
Transportation	152,515	142,093	144,580
Interdepartmental and Company use	440	393	502
Total therms delivered	1,006,413	923,096	888,301
SOURCES OF NATURAL GAS DELIVERED (Thousands of Therms):			
Purchases	877,290	787,836	751,057
Storage - injections	(109,782)	(86,750)	(99,330)
Storage - withdrawals	94,504	83,333	95,183
Natural gas for transportation	152,515	142,093	144,580
Distribution system losses	(8,114)	(3,416)	(3,189)
Total natural gas delivered	1,006,413	923,096	888,301
NUMBER OF NATURAL GAS RETAIL CUSTOMERS (Average for Period):			
Residential	284,504	282,721	280,667
Commercial	33,540	33,431	33,214
Industrial and interruptible	293	292	300
Total natural gas retail customers	318,337	316,444	314,181
NATURAL GAS RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (therms)	728	667	741
Revenue per therm (in dollars)	$ 1.06	$ 1.02	$ 1.21
Annual revenue per customer	$ 771.72	$ 683.25	$ 894.37

HEATING DEGREE DAYS: (1)			
Spokane, WA			
Actual	6,861	6,320	6,976
30-year average	6,647	6,647	6,820
% of average	103%	95%	102%
Medford, OR			
Actual	4,634	4,119	4,485
30-year average	4,402	4,402	4,533
% of average	105%	94%	99%

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

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Ecova (formerly known as Advantage IQ)

In October 2011, our subsidiary, Advantage IQ changed its name to Ecova, which combined the company and its subsidiary Ecos under one name and brand. Ecova provides sustainable utility expense management and energy management solutions to multi-site companies across North America. Ecova s invoice processing, auditing and payment services, coupled with energy procurement, comprehensive reporting and advanced analysis, provide the critical data clients need to balance the financial, social and environmental aspects of doing business.

As part of the expense management services, Ecova analyzes and audits invoices, then presents consolidated bills on-line, and processes payments. Information gathered from invoices, providers and other customer-specific data allows Ecova to provide its clients with in-depth analytical support, real-time reporting and consulting services.

Ecova also provides comprehensive energy efficiency program management services to utilities across North America. As part of these management services, Ecova helps utilities develop and execute energy efficiency programs with a complete turn-key solution.

Ecova has secured five patents on its two critical business systems:

- Facility IQ system, which provides operational information drawn from facility bills, and
- AviTrack database, which processes and reports on information gathered from service providers to ensure that customers are receiving the most effective services at the proper price.

We are not aware of potential infringement of any of Ecova s patents issued to date and we expect to continue to expand and protect existing patents, as well as file additional patent applications for new products, services and process enhancements. Furthermore, we are not aware of any claims or threatened claims that Ecova has infringed any patents held by other parties.

The following table presents key statistics for Ecova:

	2011	2010	2009
Expense management customers at year-end	645	534	532
Billed sites at year-end	496,842	360,596	421,080
Dollars of customer bills processed (in billions)	$ 18.3	$ 17.3	$ 17.4

The decrease in billed sites at year-end 2010 as compared to 2009 was due to the loss of a customer that had a significant number of billed sites, but represented only approximately 1 percent of annual revenues. On December 31, 2010, Ecova acquired The Loyalton Group, a Minneapolis-based energy management firm known for its energy procurement and price risk management solutions. In January 2011, Ecova acquired Building Knowledge Networks, a Seattle-based real-time building energy management services provider. In November 2011, Ecova acquired Prenova, an energy management company headquartered in Atlanta, Georgia. In January 2012, Ecova acquired LPB Energy Management (LPB), an energy management company headquartered in Dallas, Texas.

The noncontrolling interest of Ecova (which was 20.8 percent as of December 31, 2011) is primarily held by the previous owners of Cadence Network, a company acquired by Ecova in 2008.

Other Businesses

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.

Our other businesses also include Advanced Manufacturing and Development (AM&D) doing business as METALfx, a subsidiary that performs custom sheet metal fabrication of electronic enclosures, parts and systems for the computer, telecom, renewable energy and medical industries. Our other investments and operations include:

- real estate investments (primarily commercial office buildings),
- investments in emerging technology venture capital funds, and
- the remaining investment in a fuel cell business that was previously a subsidiary of the Company.

Over time as opportunities arise, we dispose of assets 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 fit with our overall corporate strategy.

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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:

- retail electricity and natural gas sales,
- the cost of natural gas supply,
- the cost of power supply, and
- damages to facilities.

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

The cost of natural gas supply tends to increase with increased 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 have generally been 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.

The cost of power supply can be significantly impacted 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 to a greater extent each year based on wind patterns as wind generation facilities have grown significantly in the region.

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. Therefore, the impact on our results of operations may be larger or smaller than the weather-related impact on power supply cost.

As a result of these factors operating in combination, 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.

Damages to facilities may be caused by severe weather, such as snow, ice or wind storms. The cost to implement rapid repair to such facilities can be significant. Overhead electric lines are most susceptible to such severe weather. Collateral damage from utility assets that are damaged by external forces may result in third party claims against the Company for property damage and/or personal injuries.

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We are subject to commodity price risk.

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 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.

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. 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 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.

Deferred power and natural gas costs are subject to regulatory review; costs higher than those recovered in retail rates reduce cash flows.

We defer income statement recognition and recovery from customers of certain power and natural gas costs that are higher than what is 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 are negatively affected until these costs are recovered from customers.

Our energy resource management activities may cause volatility in our cash flows and results of operations.

We engage in active hedging and resource optimization practices; however, we cannot and do not attempt to fully hedge our energy resource assets or our forecasted net positions for various time horizons. 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 do not cover the entire market price volatility exposure for our forecasted net positions. 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 requires additional transactions or dispatch decisions that impact cash flows.

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Financial market conditions may impact our results of operations and our liquidity.

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 could have an impact on our operations. We could experience increased borrowing costs or limited access to capital on reasonable terms.

We need to 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 access to credit from financial institutions for short-term borrowings.

We need to maintain access to adequate levels of credit with financial institutions for short-term liquidity. We have a $400 million committed line of credit, which is scheduled to expire in February 2017. We cannot guarantee that we will have access to credit beyond the expiration date. The committed line of credit agreement contains 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.

Ecova has a $60 million committed line of credit, which is scheduled to expire in April 2014. In accordance with the agreement, the amount of this credit facility will be reduced to $55 million on September 30, 2012 and $50 million on December 31, 2012. Following the acquisition of LPB in January 2012, this credit agreement is fully utilized. Ecova expects to expand this facility in 2012. However, we cannot guarantee that Ecova will be able to expand this facility or have access to credit beyond the expiration date.

Downgrades in our credit ratings could limit 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 that are associated with the utility industry.

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

- blackouts or disruptions to distribution, transmission or transportation systems,
- forced 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.

As protection against operational and event risks, we 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 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 security attacks, terrorism or other malicious acts could disrupt our business and have a negative impact on our results of operations and cash flows.

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In the course of our operations, we rely on interconnected information technology systems for operation of our generating plants, electric transmission and distribution systems, natural gas distribution, customer billing and customer service, accounting and other administrative processes and compliance with various regulations. There are various risks associated with information 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 security attacks, terrorism or other malicious acts could damage, destroy or disrupt these systems. Any failure of information 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 and result in costly litigation. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or obtain specific insurance coverage against potential losses.

We are currently the subject of several regulatory proceedings, and we are named in multiple lawsuits related to our participation in western energy markets.

Through our utility operations and the prior operations of Avista Energy, we are involved in a number of legal and regulatory proceedings and complaints related to energy markets in the western United States. Most of these proceedings and complaints relate to the significant increase in the spot market price of energy in 2000 and 2001. This allegedly contributed to or caused unjust and unreasonable prices. These proceedings and complaints include, but are not limited to:

- refund proceedings in California and the Pacific Northwest,
- market conduct investigations by the FERC, and
- complaints filed by various parties related to alleged misconduct by parties in western power markets.

As a result of these proceedings and complaints, certain parties have asserted claims for significant refunds and damages from us, which could result in a negative effect on our results of operations and cash flows. See Note 21 of the Notes to Consolidated Financial Statements for further information.

We are subject to legislation and related administrative rulemaking, 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.

Concerns over long-term global climate changes may affect our operational and financial performance.

Legislative developments and advocacy at the state, national and international levels about climate change and other environmental concerns may 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 21 of the Notes to Consolidated Financial Statements for further details of these matters including:

- alleged contamination from the holding ponds at Colstrip in Montana,
- waste oil delivered to the Harbor Oil, Inc. site in Portland, Oregon, and
- aluminum dross located on a parcel of land we own near the Spokane River.

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.

Item 2. Properties

Avista Utilities

Substantially all of our utility properties are subject to the lien of our 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	87.0
Little Falls (Spokane)	4	32.0	34.6
Nine Mile (Spokane)	3	26.4	17.6
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork) (3)	4	265.0	254.6
Post Falls (Spokane)	6	14.8	18.0

Montana:			
Noxon Rapids (Clark Fork)	5	480.6	562.4
Total Hydroelectric		913.6	999.4
Thermal Generating Stations			
Washington:			
Kettle Falls GS	1	50.7	50.0
Kettle Falls CT	1	7.2	6.9
Northeast CT	2	61.8	61.2
Boulder Park	6	24.6	24.0
Idaho:			
Rathdrum CT	2	166.5	149.0
Montana:			
Colstrip Units 3 and 4 (4)	2	233.4	222.0
Oregon:			
Coyote Springs 2	1	287.0	278.3
Total Thermal		831.2	791.4
Total Generation Properties		1,744.8	1,790.8

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(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, 2011.
(3) The present capability of Cabinet Gorge is limited by our water rights. This output level reflects the maximum capability within our water rights. When river flows exceed these water rights limits, we are permitted to increase flow through the plant resulting in up to 265 MW.
(4) Jointly owned; data refers to our 15 percent interest.

Electric Distribution and Transmission Plant

We operate approximately 18,300 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of 685 miles of 230 kV line and 1,535 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 Bonneville Power Administration (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

We have natural gas distribution mains of approximately 3,400 miles in Washington, 1,950 miles in Idaho and 2,300 miles in Oregon. We have natural gas transmission mains of approximately 75 miles in Washington and 40 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 the Jackson Prairie Natural Gas Storage Project (Jackson Prairie), an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 11.5 million therms, with a total working natural gas capacity of 253 million therms. Natural gas storage enables us to place natural gas into storage when prices are lower or to satisfy minimum natural gas purchasing requirements, as well as to meet high demand periods or to withdraw natural gas from storage when spot prices are higher.

Avista Utilities gained 30.3 million therms of additional capacity at Jackson Prairie on May 1, 2011 for use in its utility operations. This capacity was originally held by Avista Energy and as part of the asset sales agreement this capacity had been assigned to Shell Energy through April 30, 2011.

Item 3. Legal Proceedings

See Note 21 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

Our common stock is currently listed on the New York Stock Exchange under the ticker symbol AVA . As of January 31, 2012, there were 10,693 registered shareholders of our common stock.

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

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

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

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock (when outstanding) contained in our Restated Articles of Incorporation, as amended.

On February 3, 2012, Avista Corp. s Board of Directors declared a quarterly dividend of $0.29 per share on the Company s common stock. This was an increase of $0.015 per share, or 5 percent from the previous quarterly dividend of $0.275 per share.

For additional information, refer to Notes 1, 18, 19 and 20 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
2011				
Dividends paid per common share	$ 0.275	$ 0.275	$ 0.275	$ 0.275
Trading price range per common share:				
High	$ 23.69	$ 25.83	$ 26.53	$ 26.35
Low	$ 21.78	$ 22.81	$ 21.13	$ 23.14
2010				
Dividends paid per common share	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Trading price range per common share:				
High	$ 22.37	$ 22.25	$ 21.88	$ 22.81
Low	$ 19.19	$ 18.46	$ 19.05	$ 20.90

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.

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Item 6. Selected Financial Data

(in thousands, except per share data and ratios)	Years Ended December 31, 2011	2010	2009	2008	2007
Operating Revenues:					
Avista Utilities	$ 1,443,322	$ 1,419,646	$ 1,395,201	$ 1,572,664	$ 1,288,363
Ecova	137,848	102,035	77,275	59,085	47,255
Other	40,410	61,067	40,089	45,014	82,139
Intersegment eliminations	(1,800)	(24,008)			
Total	$ 1,619,780	$ 1,558,740	$ 1,512,565	$ 1,676,763	$ 1,417,757
Income (Loss) from Operations (pre-tax):					
Avista Utilities	$ 208,970	$ 208,104	$ 195,389	$ 174,245	$ 150,053
Ecova	20,917	15,865	11,603	11,297	11,012
Other	5,735	6,219	(6,334)	(631)	(22,636)
Total	$ 235,622	$ 230,188	$ 200,658	$ 184,911	$ 138,429
Net income	$ 103,539	$ 94,948	$ 88,648	$ 74,757	$ 38,727
Net income attributable to noncontrolling interests	$ (3,315)	$ (2,523)	$ (1,577)	$ (1,137)	$ (252)
Net Income (Loss) Attributable to Avista Corporation:					
Avista Utilities	$ 90,902	$ 86,681	$ 86,744	$ 70,032	$ 43,822
Ecova	9,671	7,433	5,329	6,090	6,651
Other	(349)	(1,689)	(5,002)	(2,502)	(11,998)
Total	$ 100,224	$ 92,425	$ 87,071	$ 73,620	$ 38,475
Average common shares outstanding, basic	57,872	55,595	54,694	53,637	52,796
Average common shares outstanding, diluted	58,092	55,824	54,942	54,028	53,263
Common shares outstanding at year-end	58,423	57,120	54,837	54,488	52,909
Earnings per Common Share Attributable to Avista Corporation:					
Diluted	$ 1.72	$ 1.65	$ 1.58	$ 1.36	$ 0.72
Basic	$ 1.73	$ 1.66	$ 1.59	$ 1.37	$ 0.73
Dividends paid per common share	$ 1.10	$ 1.00	$ 0.81	$ 0.69	$ 0.595
Book value per common share at year-end	$ 20.30	$ 19.71	$ 19.17	$ 18.30	$ 17.27
Total Assets at Year-End:					
Avista Utilities	$ 3,809,446	$ 3,589,235	$ 3,400,384	$ 3,434,844	$ 3,009,499
Ecova	292,940	221,086	143,060	125,911	108,929
Other	112,145	129,774	63,515	69,992	71,369
Total	$ 4,214,531	$ 3,940,095	$ 3,606,959	$ 3,630,747	$ 3,189,797

Long-Term Debt (including current portion)	$ 1,177,300	$ 1,101,857	$ 1,071,338	$ 826,465	$ 948,833
Nonrecourse Long-Term Debt of Spokane Energy (including current portion) (1)	$ 46,471	$ 58,934	$	$	$
Long-Term Debt to Affiliated Trusts	$ 51,547	$ 51,547	$ 51,547	$ 113,403	$ 113,403
Total Avista Corporation Stockholders Equity	$ 1,185,701	$ 1,125,784	$ 1,051,287	$ 996,883	$ 913,966
Ratio of Earnings to Fixed Charges (2)	3.06	2.86	2.95	2.43	1.67

(1) Spokane Energy was consolidated effective January 1, 2010. See Note 3 of the Notes to Consolidated Financial Statements.

(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

We have two reportable business segments as follows:

- **Avista Utilities** an operating division of Avista Corp. that comprises our regulated utility operations. Avista Utilities generates, transmits and distributes electricity and distributes natural gas. The utility also engages in wholesale purchases and sales of electricity and natural gas.

- **Ecova (formerly known as Advantage IQ)** an indirect subsidiary of Avista Corp. (79.2 percent owned as of December 31, 2011) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Ecova s primary product lines include expense management services for utility and telecom needs as well as strategic energy management and efficiency services that include procurement, conservation, performance reporting, financial planning and energy efficiency program management for commercial enterprises and utilities.

We have other businesses, including sheet metal fabrication, venture fund investments and real estate investments, Spokane Energy (see Note 3) as well as certain other operations of Avista Capital. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp., including AM&D, doing business as METALfx.

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

	2011	2010	2009
Avista Utilities	$ 90,902	$ 86,681	$ 86,744
Ecova	9,671	7,433	5,329
Other	(349)	(1,689)	(5,002)
Net income attributable to Avista Corporation	$ 100,224	$ 92,425	$ 87,071

Executive Level Summary

Overall

Net income attributable to Avista Corporation was $100.2 million for 2011, an increase from $92.4 million for 2010. This was primarily due to an increase in earnings at Avista Utilities (primarily due to colder weather during the first quarter and the implementation of general rate increases, partially offset by an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes) and partially due to an increase in earnings at Ecova, as well as a reduction in the net loss from the Other businesses. The first quarter of 2011 was significantly colder than the first quarter of 2010 and slightly colder than average. The first quarter of 2010 was one of the warmest January to March periods on record in our service territory.

Avista Utilities

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

- weather conditions,
- 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,
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand, and
- the 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.

In our utility operations, we regularly review the need for rate changes in each jurisdiction to improve the recovery of costs and capital investments in our generation, transmission and distribution systems. General rate increases went into effect in Idaho on October 1, 2010 and October 1, 2011, in Washington effective December 1, 2010 and January 1, 2012, and in Oregon effective March 15, 2011 and June 1, 2011.

Our utility net income was $90.9 million for 2011, an increase from $86.7 million for 2010. Earnings for 2011 were positively impacted by an increase in gross margin (operating revenues less resource costs). The increase in gross margin was primarily due to higher retail loads caused by colder weather during the first quarter and general rate increases. The increase in gross margin was partially offset by an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes. The increase in other operating expenses was primarily due to increased maintenance costs, pensions and other postretirement benefits expense, and labor costs.

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Above normal snowpack last winter, and a cool and wet spring produced excellent river run-off conditions in 2011. This resulted in one of the best hydroelectric generation years on record. In addition, purchased power and natural gas fuel prices were below the level included in base rates. As such, the Company received a benefit of $6.4 million and $12.9 million was deferred for the future benefit of customers under the Energy Recovery Mechanism in Washington.

We are making significant capital investments in generation, transmission and distribution systems to preserve and enhance service reliability for our customers and replace aging infrastructure. Utility capital expenditures were $239.8 million for 2011. We expect utility capital expenditures to be about $250 million for each of 2012 and 2013. These estimates of capital expenditures are subject to continuing review and adjustment (see discussion under Avista Utilities Capital Expenditures).

Ecova

Ecova had net income attributable to Avista Corporation of $9.7 million for 2011, an increase from $7.4 million for 2010. This increase was primarily due to strong growth in energy management services, moderate growth from expense management, as well as the acquisition of The Loyalton Group (Loyalton) effective December 31, 2010. Ecova s earnings potential continues to be moderated by low short-term interest rates, which limits interest revenue on funds held for clients.

On November 30, 2011, Ecova acquired Prenova, Inc. (Prenova), an Atlanta-based energy management company. The cash paid for the acquisition of Prenova of $35.6 million was funded primarily through borrowings under Ecova s committed credit agreement.

In January 2012, Ecova acquired LPB Energy Management (LPB), a Dallas-based energy management company. The cash paid for the acquisition of LPB of $50.3 million was funded by Ecova through $25.0 million of borrowings under its committed credit agreement, a $20.0 million equity infusion from existing shareholders (including Avista Capital and the other owners of Ecova), and available cash.

While we do not expect these acquisitions to have an impact on 2012 earnings, they increase Ecova s market share and allow Ecova to offer its clients a broader range of services leading to potential future earnings growth.

The acquisition of Cadence Network in July 2008 was funded with the issuance of Ecova common stock. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Ecova common stock redeemed by Ecova during July 2011 or July 2012 if Ecova is not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised in July 2011. These redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Ecova at the time of the redemption election as determined by certain independent parties. As of December 31, 2011, there were redeemable noncontrolling interests of $38.9 million related to these redemption rights. Should the previous owners of Cadence Network exercise their redemption rights, Ecova will seek the necessary funding through its credit facility, a capital request from existing owners, an infusion of capital from potential new investors or a combination of these sources. In January 2011, Avista Capital purchased shares held by one of the previous owners of Cadence Network for $5.6 million.

We may seek to monetize all or part of our investment in Ecova in the future, regardless of whether Ecova s minority owner redemption rights are exercised. The value of a potential monetization depends on future market conditions, growth of the business and other factors. This may provide access to public market capital and provide potential liquidity to Avista Corp. and the other owners of Ecova. There can be no assurance that such a transaction will be completed.

Other Businesses

The net loss for these operations was $0.3 million for 2011 compared to a net loss of $1.7 million for 2010. The improvement in results was due in part to increased earnings at METALfx and a decrease in the net loss on investments. Also, in 2010, we recorded a $2.2 million impairment of our investment in a fuel cell business.

Liquidity and Capital Resources

We need to access long-term capital markets from time to time to finance capital expenditures, repay maturing long-term debt and obtain additional working capital. Our ability to access capital on reasonable terms is subject to numerous factors, many of which, including market conditions, are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or eliminate 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.

In February 2011, we entered into a new committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2015 that replaced our $320.0 million and $75.0 million committed lines of credit that had expiration dates in April 2011. In December 2011, this committed line of credit was amended to extend the expiration date to February 2017 and improve the pricing terms. As of December 31, 2011, there were $61.0 million of cash borrowings and $29.0 million in letters of credit outstanding. As of December 31, 2011, we had $310.0 million of available liquidity under this line of credit.

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In December 2011, we issued $85.0 million of 4.45 percent First Mortgage Bonds due in 2041. The net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit. We expect to issue up to $100.0 million of long-term debt in 2012.

In September 2011, we cash settled interest rate swap contracts (notional amount of $85.0 million) and paid a total of $10.6 million. The interest rate swap contracts were entered during the third quarter of 2011 and were settled in connection with the pricing of $85.0 million of First Mortgage Bonds as described above. Upon settlement of the interest rate swaps, the regulatory asset (included as part of long-term debt) is amortized as a component of interest expense over the life of the forecasted interest payments.

In 2011, we issued $26.5 million of common stock, including $19.5 million under a sales agency agreement.

We expect to issue up to $45 million of common stock from time to time in 2012 in order to maintain our capital structure at an appropriate level for our business. We have 0.2 million shares available to be issued under the sales agency agreement and we expect to expand this agreement for a significant portion of our 2012 common stock issuances. After considering the issuances of long-term debt and common stock during 2012, we expect net cash flows from operating activities, together with cash available under our $400.0 million committed line of credit agreement, to provide adequate resources to fund:

- capital expenditures,
- dividends, and
- other contractual commitments.

Avista Utilities   Regulatory Matters

General Rate Cases

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

- provide for recovery of operating costs and capital investments, and
- provide the opportunity to improve our earned 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. We filed general rate cases in Washington in May 2011 (which was settled with new rates effective January 1, 2012) and in Idaho in July 2011 (which was settled with new rates effective October 1, 2011). We expect to file general rate cases in Washington in the second quarter of 2012 and in Idaho in the second half of 2012.

Washington General Rate Cases

In December 2009, the WUTC issued an order in our electric and natural gas general rate cases that were filed with the WUTC in January 2009. The WUTC approved a base electric rate increase for our Washington customers of 2.8 percent, which was designed to increase annual revenues by $12.1 million. Base natural gas rates for our Washington customers increased by an average of 0.3 percent, which was designed to increase annual revenues by $0.6 million. The new electric and natural gas rates became effective on January 1, 2010.

In November 2010, the WUTC approved an all-party settlement stipulation in our general rate case filed in March 2010. As agreed to in the settlement stipulation, electric rates for Washington customers increased by an average of 7.4 percent, which was designed to increase annual revenues by $29.5 million. Natural gas rates for Washington customers increased by an average of 2.9 percent, which was designed to increase annual revenues by $4.6 million. The new electric and natural gas rates became effective on December 1, 2010.

In December 2011, the WUTC approved a settlement agreement in our electric and natural gas general rate cases filed in May 2011. As agreed to in the settlement agreement, base electric rates for our Washington customers increased by an average of 4.6 percent, which is designed to increase annual revenues by $20.0 million. Base natural gas rates for our Washington customers increased by an average of 2.4 percent, which is designed to increase annual revenues by $3.75 million. The new electric and natural gas rates became effective on January 1, 2012. No capital structure ratios or cost of capital components were specified in the settlement agreement. As part of the settlement agreement, we agreed to not file a general rate case in Washington prior to April 1, 2012.

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The settlement agreement also provides for the deferral of certain generation plant maintenance costs. In order to address the variability in year-to-year maintenance costs, beginning in 2011, we are deferring changes in maintenance costs related to our Coyote Spring 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. We compare actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and defer the difference. The deferral will occur annually, with no carrying charge, with deferred costs being amortized over a four-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases would be the actual maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. For 2011, we deferred $0.5 million of maintenance costs in Washington.

Idaho General Rate Cases

In July 2009, the IPUC approved a settlement agreement in our general rate cases that were filed with the IPUC in January 2009. The new electric and natural gas rates became effective on August 1, 2009. As agreed to in the settlement, base electric rates for our Idaho customers increased by an average of 5.7 percent, which was designed to increase annual revenues by $12.5 million. Base natural gas rates for our Idaho customers increased by an average of 2.1 percent, which was designed to increase annual revenues by $1.9 million.

In September 2010, the IPUC approved a settlement agreement with respect to our general rate case filed in March 2010. The new electric and natural gas rates became effective on October 1, 2010. As agreed to in the settlement, base electric rates for our Idaho customers increased by an average of 9.3 percent, which was designed to increase annual revenues by $21.2 million. Base natural gas rates for our Idaho customers increased by an average of 2.6 percent, which was designed to increase annual revenues by $1.8 million.

The settlement agreement included a rate mitigation plan under which the impact on customers of the new rates was reduced by amortizing $11.1 million ($17.5 million when grossed up for income taxes and other revenue-related items) of previously deferred state income taxes over a two-year period as a credit to customers. While our cash collections from customers are reduced by this amortization during the two-year period, the mitigation plan has no impact on our net income. Retail rates increased on October 1, 2011 and will increase on October 1, 2012 as the previous deferred state income tax balance is amortized.

In September 2011, the IPUC approved a settlement agreement in our general rate case filed in July 2011. The new electric and natural gas rates became effective on October 1, 2011. As agreed to in the settlement agreement, base electric rates for our Idaho customers increased by an average of 1.1 percent, which is designed to increase annual revenues by $2.8 million. Base natural gas rates for our Idaho customers increased by an average of 1.6 percent, which is designed to increase annual revenues by $1.1 million.

As part of the settlement agreement, we agreed not to file a general rate case seeking a change in base electric or natural gas rates effective prior to April 1, 2013. This does not preclude us from filing annual rate adjustments such as the PCA and the PGA.

The settlement agreement also provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, we are deferring changes in operation and maintenance costs related to the Coyote Spring 2 natural gas-fired generation plant and our 15 percent ownership interest in Units 3&4 of the Colstrip generation plant. We compare actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defer the difference from that currently authorized. The deferral will occur annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. For 2011, we deferred $0.1 million of maintenance costs in Idaho.

Oregon General Rate Cases

In September 2009, we entered into an all-party settlement stipulation in our general rate case that was filed with the OPUC in June 2009. This settlement stipulation was approved by the OPUC in October 2009. The new natural gas rates became effective on November 1, 2009. As agreed to in the settlement, base natural gas rates for our Oregon customers increased by an average of 7.1 percent, which was designed to increase annual revenues by $8.8 million.

In March 2011, the OPUC approved an all-party settlement stipulation in our general rate case that was filed in September 2010. The settlement provides for an overall rate increase of 3.1 percent for our Oregon customers, designed to increase annual revenues by $3.0 million. Part of the rate increase became effective March 15, 2011, with the remaining increase effective June 1, 2011. An additional rate adjustment designed to increase revenues by $0.6 million will occur on June 1, 2012 to recover capital costs associated with certain reinforcement and replacement projects upon a demonstration that such projects are complete and the costs were prudently incurred.

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Proposed Electric Decoupling Washington

In the September 2011 Washington general rate case settlement (which was approved by the WUTC in December 2011), one party, the Northwest Energy Coalition (NWEC), did not sign the agreement and is pursuing an electric decoupling mechanism in Washington. The issue of electric decoupling is being addressed through a separate procedural schedule. Decoupling separates the link between actual kWh sales and the recovery of our fixed costs. In summary, the NWEC proposes that actual fixed cost recovery per customer be compared to authorized fixed cost recovery per customer, and any difference be deferred for later surcharge or rebate to customers. The WUTC has established a procedural schedule that would provide for a decision in the second quarter of 2012.

Purchased Gas Adjustments

Effective October 1, 2011, natural gas rates increased 1.0 percent in Idaho. Effective November 1, 2011, natural gas rates increased 1.0 percent in Washington, while decreasing 0.2 percent in Oregon. Effective November 1, 2010, natural gas rates increased 4.6 percent in Washington and 4.3 percent in Idaho, while decreasing 3.2 percent in Oregon. Effective November 1, 2009, natural gas rates decreased 22 percent in Oregon, 26 percent in Washington and 23 percent in Idaho. In Oregon, we absorb (gain or loss) 10 percent of the difference between actual and projected gas costs for supply that is not hedged. Total net deferred natural gas costs were a liability of $12.1 million as of December 31, 2011, a decrease from $22.1 million as of December 31, 2010. In February 2012, we filed PGA requests with the respective utility commissions to decrease natural gas rates 6.4 percent in Washington and 6.0 percent in Idaho effective March 1, 2012. PGAs are designed to pass through changes in natural gas costs to our customers with no change in gross margin (operating revenues less resource costs) or net income.

Power Cost Deferrals and Recovery Mechanisms

The Energy Recovery Mechanism (ERM) is an accounting method used to track certain differences between actual power supply costs, net of the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for our Washington customers. In the 2010 Washington general rate case settlement, the parties agreed that there would be no deferrals under the ERM in 2010. Deferrals under the ERM resumed in 2011. Total net deferred power costs under the ERM were a liability of $12.9 million as of December 31, 2011.

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

- short-term wholesale market prices and sales and purchase volumes,
- the level of hydroelectric generation,
- the level of thermal generation (including changes in fuel prices), and
- retail loads.

Under the ERM, we absorb the cost or receive the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. We incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. We share annual power supply cost variances between $4.0 million and $10.0 million with customers. There is a 50 percent customers/50 percent Company sharing 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 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 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
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess over $10 million	90%	10%

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Under the ERM, we make an annual filing on or before April 1 of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by WUTC order. Additionally, we must make a filing (no sooner than June 2011), to allow all interested parties the opportunity to review the ERM, and make recommendations to the WUTC related to the continuation, modification or elimination of the ERM.

We have a Power Cost Adjustment (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 a regulatory liability of $0.7 million as of December 31, 2011 compared to a regulatory asset of $18.3 million as of December 31, 2010.

Natural Gas Safety Regulations

On February 3, 2012, President Obama signed into law the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 mandating new regulations be created to address public safety concerns. Regulations include requiring automatic shut-off valves on pipeline mains, increased installation of excess flow valves on gas service piping, increased high consequence area boundaries as well as to provide additional scrutiny on existing emergency preparedness plans, quality assurance plans and damage prevention programs and broader federal oversight including broader use of fines and penalties to pipeline operators are included in the Act. We are evaluating the Act and cannot predict the impact the Act may ultimately have on our operations.

In addition, the Pipeline and Hazardous Materials Safety Administration issued an Advisory Bulletin in January 2011 to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under federal integrity management regulations, to perform detailed threat and risk analyses especially with regards to their pipelines maximum allowable operating pressures. While we believe that we operate our pipeline systems in a safe manner, we cannot predict the impact of any future regulations or inspections on our natural gas system.

Results of Operations

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

2011 compared to 2010

Utility revenues increased $23.7 million, after elimination of intracompany revenues of $93.1 million in 2011 and $65.9 million in 2010. Including intracompany revenues, electric revenues increased $13.9 million and natural gas revenues increased $37.0 million. Retail electric revenues increased $51.1 million due to general rate increases and an increase in volumes sold caused by colder weather during the first three months of 2011 compared to 2010. In addition, sales of fuel increased $47.1 million (reflecting lower usage of our thermal generating plants and sales of natural gas fuel not used in generation). These increases in retail electric revenues and sales of fuel were partially offset by a decrease in wholesale electric revenues of $87.2 million (due to a decrease in wholesale prices and volumes). Retail natural gas revenues increased $40.3 million due to an increase in volumes caused by colder weather and prices from rate increases, while wholesale natural gas revenues decreased $1.5 million.

Non-utility revenues increased $37.4 million to $178.3 million primarily as a result of Ecova s revenues increasing $35.8 million primarily due to growth in expense management and energy management services, as well as the acquisition of Loyalton effective December 31, 2010. Revenues from our other businesses increased $1.6 million (excluding intercompany revenues) primarily due to increased sales at METALfx.

Utility resource costs decreased $5.0 million, after elimination of intracompany resource costs of $93.1 million in 2011 and $65.9 million in 2010. Including intracompany resource costs, electric resource costs increased $5.1 million and natural gas resource costs increased $17.1

million. The increase in electric resource costs was primarily due to an increase in 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 amortization of deferred power supply costs, partially offset by a decrease in fuel costs (due to lower thermal generation) and power purchased (due in part to higher hydroelectric generation). The increase in natural gas resource costs was primarily due to an increase in natural gas purchased due to an increase in retail sales.

Utility other operating expenses increased $12.8 million primarily due to increased maintenance expenses (including planned major maintenance at Colstrip), pensions and other postretirement benefits, and labor.

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

Utility taxes other than income taxes increased $10.0 million primarily reflecting higher retail revenue related taxes, as well as increased property taxes.

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Non-utility other operating expenses increased $31.9 million primarily due to an increase of $29.6 million for Ecova reflecting increased costs necessary for business growth and the acquisition of Loyalton.

Interest expense decreased $1.9 million primarily due to refinancing transactions completed in December 2010 that lowered our effective rate on long-term debt. This was partially offset by higher interest rates on short-term borrowings.

Capitalized interest increased $2.6 million due to higher average construction work in progress balances and higher borrowing rates (including an increase on short-term borrowing rates used in the calculation).

Other expense-net decreased $3.8 million primarily due to a decrease in donations, a decrease in losses on investments (including a $2.2 million impairment of our investment in a fuel cell business recorded in 2010), partially offset by a decrease in equity-related AFUDC.

Income taxes increased $5.5 million and our effective tax rate was 35.4 percent for 2011 compared to 35.0 percent for 2010. This increase in expense was primarily due to an increase in income before income taxes. Adjustments associated with reconciling the 2009 federal income tax return to the amount included in the financial statements for 2009 and prior year income tax return amendments decreased income tax expense by $1.7 million for 2010.

2010 compared to 2009

Utility revenues increased $22.6 million due to increased electric revenues of $133.5 million, partially offset by decreased natural gas revenues of $43.2 million and intracompany revenues of $65.9 million. Wholesale electric revenues increased $77.1 million (primarily due to an increase in volumes sold and partially due to an increase in wholesale prices) and sales of fuel increased $73.4 million (reflecting increased thermal generation resource optimization). These increases in electric revenues were partially offset by a decrease in retail electric revenues of $20.6 million, due to a decrease in volumes sold and prices resulting from the elimination of the ERM surcharge in February 2010, offset by general rate increases. Retail natural gas revenues decreased $98.3 million (due to decreased retail rates and decreased volumes), while wholesale natural gas revenues increased $53.8 million (due to increased volumes and wholesale prices).

Non-utility revenues increased $23.5 million to $140.9 million primarily as a result of Ecova s revenues increasing $24.7 million primarily due to the acquisition of Ecos in the third quarter of 2009, as well as moderate growth in expense management and energy management services.

Utility resource costs decreased $4.5 million as natural gas resource costs decreased $38.8 million and intracompany resource costs decreased $65.9 million, while electric resource costs increased $100.2 million. The decrease in natural gas resource costs primarily reflects the purchased gas cost adjustments implemented in the fourth quarter of 2009. The increase in electric resource costs was primarily due to an increase in fuel costs (due to an increase in thermal 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).

Utility other operating expenses increased $12.6 million primarily due to increased outside services (primarily consulting costs) of $5.1 million, compensation costs of $3.6 million, as well as injuries and damages of $1.9 million.

Utility depreciation and amortization increased $6.8 million driven by additions to utility plant.

Utility taxes other than income taxes decreased $3.2 million primarily reflecting lower retail revenue related taxes, partially offset by increased property taxes.

Other non-utility operating expenses increased $3.8 million reflecting an increase of $19.1 million for Ecova due to the acquisition of Ecos in the third quarter of 2009, as well as moderate growth in expense management and energy management services. The increase was partially offset by decreased operating expenses from the other businesses primarily due to the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations for this agreement were conveyed to Shell Energy through the end of 2009. These rights and obligations were conveyed to Avista Utilities operations in January 2010.

Interest expense increased $10.7 million primarily due to the consolidation of Spokane Energy (increased interest expense $5.5 million) and the issuance of $250.0 million of long-term debt in September 2009. During 2009, we carried relatively high balances on our committed line of credit at relatively low interest rates. This was replaced with long-term debt at a higher interest rate.

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Interest expense to affiliated trusts decreased $1.3 million because of the redemption of $61.9 million of long-term debt to affiliated trusts in April 2009 and a decrease in the variable interest rate on the remaining debt outstanding.

Other expense-net increased $8.8 million primarily due to an increase in donations, a decrease in interest income (primarily interest on regulatory deferrals due to lower balances) and a $2.2 million impairment of our investment in a fuel cell business.

Income taxes increased $4.8 million and our effective tax rate was 35.0 percent for 2010 compared to 34.3 percent for 2009. This increase was due in part to an increase in income before income taxes. Adjustments associated with reconciling the 2009 federal income tax return to the amount included in the financial statements for 2009 and prior year income tax return amendments decreased income tax expense by $1.7 million for 2010 (recorded in the third quarter). In 2009, we recorded adjustments related to Internal Revenue Service (IRS) audits and adjustments for the 2008 filed federal tax return that had a favorable impact to income tax expense of $3.2 million (Avista Utilities) for 2009 (recorded in the third quarter).

Avista Utilities

2011 compared to 2010

Net income for Avista Utilities was $90.9 million for 2011, an increase from $86.7 million for 2010. Avista Utilities income from operations was $209.0 million for 2011 compared to $208.1 million for 2010. The increase in net income and income from operations was primarily due to an increase in gross margin (operating revenues less resource costs), partially offset by an increase in other operating expenses, depreciation and amortization, and taxes other than income taxes. The increase in net income from Avista Utilities was also due to a decrease in interest expense (net of capitalized interest) and a decrease in donations (included in other expenses).

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	
	2011	2010	2011	2010	2011	2010	2011	2010
Operating revenues	$ 988,187	$ 974,283	$ 548,225	$ 511,249	$ (93,090)	$ (65,886)	$ 1,443,322	$ 1,419,646
Resource costs	484,359	479,252	398,779	381,709	(93,090)	(65,886)	790,048	795,075
Gross margin	$ 503,828	$ 495,031	$ 149,446	$ 129,540	$	$	$ 653,274	$ 624,571

Avista Utilities operating revenues increased $23.7 million and resource costs decreased $5.0 million, which resulted in an increase of $28.7 million in gross margin. The gross margin on electric sales increased $8.8 million and the gross margin on natural gas sales increased $19.9 million. The increase in electric gross margin was due to colder weather during the first quarter of 2011 that increased retail loads and general rate increases. For 2011, we recognized a benefit of $6.4 million under the ERM in Washington. As part of a rate case settlement there were no deferrals under the ERM in 2010. For 2010, power supply costs were $7.1 million below the level included in base retail rates in Washington. The increase in our natural gas gross margin was primarily due to colder weather that increased retail loads (particularly in the first quarter) and partially due to general rate increases.

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 Avista Utilities total results and in the consolidated financial statements.

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	
	2011	2010	2011	2010
Residential	$ 324,835	$ 296,627	3,728	3,618
Commercial	280,139	265,219	3,122	3,100
Industrial	122,560	114,792	2,147	2,099
Public street and highway lighting	6,941	6,702	26	26
Total retail	734,475	683,340	9,023	8,843
Wholesale	78,305	165,553	2,796	3,803
Sales of fuel	153,470	106,375		
Other	21,937	19,015		
Total	$ 988,187	$ 974,283	11,819	12,646

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Retail electric revenues increased $51.1 million due to an increase in total MWhs sold (increased revenues $14.6 million) primarily due to an increase in use per customer as a result of colder weather, and an increase in revenue per MWh (increased revenues $36.5 million). Compared to 2010, residential electric use per customer increased 3 percent and commercial use per customer increased 1 percent. The increase in revenue per MWh was primarily due to the Washington and Idaho general rate increases.

Wholesale electric revenues decreased $87.2 million due to a decrease in sales prices (decreased revenues $59.0 million) and a decrease in sales volumes (decreased revenues $28.2 million). The decrease in sales volumes was primarily due to decreased wholesale power optimization and higher than expected retail sales caused by colder weather in the first quarter.

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market rather than operate the generating units. The revenues from sales of fuel increased $47.1 million due to an increase in sales of natural gas fuel as part of thermal generation resource optimization activities and lower usage of our thermal generation plants in 2011 as compared to 2010. This was due in part to increased hydroelectric generation. In 2011, $38.6 million of these sales were made to our natural gas operations and are included as intracompany revenues and resource costs. In 2010, $24.7 million of these sales were made to our natural gas operations.

The net margin on wholesale sales and sales of fuel is applied to reduce or increase resource costs as accounted for under the ERM, the PCA mechanism, and in general rate cases as part of base power supply costs.

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2011	2010	2011	2010
Residential	$ 219,557	$ 193,169	207,202	188,546
Commercial	111,964	98,257	125,344	113,422
Interruptible	2,519	2,738	4,503	4,443
Industrial	4,180	3,756	5,654	5,312
Total retail	338,220	297,920	342,703	311,723
Wholesale	195,882	197,364	510,755	468,887
Transportation	6,709	6,470	152,515	142,093
Other	7,414	9,495	440	393
Total	$ 548,225	$ 511,249	1,006,413	923,096

Retail natural gas revenues increased $40.3 million due to an increase in volumes (increased revenues $30.6 million) and higher retail rates (increased revenues $9.7 million). We sold more retail natural gas in 2011 as compared to 2010 primarily due to colder weather in the heating season. Compared to 2010, residential natural gas use per customer increased 9 percent and commercial use per customer increased 10 percent. The increase in retail rates reflects purchased gas adjustments, as well as general rate increases.

Wholesale natural gas revenues decreased $1.5 million due to a decrease in prices (decreased revenues $17.5 million), partially offset by an increase in volumes (increased revenues $16.0 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, we generally have more pipeline and storage capacity than what is needed. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs. We hedge against expected natural gas volumes with forward purchases. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. In 2011, $54.5 million of these sales were made to our electric generation operations and are included as intracompany revenues and resource costs. In 2010, $41.2 million of these sales were made to our electric generation operations. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.

The following table presents our average number of electric and natural gas retail customers for the year ended December 31:

	Electric Customers		Natural Gas Customers	
	2011	2010	2011	2010
Residential	316,762	315,283	284,504	282,721
Commercial	39,618	39,489	33,540	33,431
Interruptible			38	38
Industrial	1,380	1,376	255	254
Public street and highway lighting	455	449		
Total retail customers	358,215	356,597	318,337	316,444

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The following table presents our utility resource costs for the year ended December 31 (dollars in thousands):

	2011	2010
Electric resource costs:		
Power purchased	$ 169,845	$ 186,312
Power cost amortizations, net	31,910	2,798
Fuel for generation	84,367	142,154
Other fuel costs	164,173	114,211
Other regulatory amortizations, net	16,381	17,772
Other electric resource costs	17,683	16,005
Total electric resource costs	484,359	479,252
Natural gas resource costs:		
Natural gas purchased	396,497	386,828
Natural gas cost amortizations, net	(10,041)	(18,741)
Other regulatory amortizations, net	12,323	13,622
Total natural gas resource costs	398,779	381,709
Intracompany resource costs	(93,090)	(65,886)
Total resource costs	$ 790,048	$ 795,075

Power purchased decreased $16.5 million due to a decrease in the volume of power purchases (decreased costs $18.0 million), partially offset by a slight increase in wholesale prices (increased costs $1.5 million). The decrease in the volume of the power purchases was due in part to an increase in hydroelectric generation.

Net amortization of deferred power costs was $31.9 million for 2011 compared to $2.8 million for 2010. During 2011, we recovered (collected as revenue) $14.9 million of previously deferred power costs in Idaho through the PCA surcharge. The Washington ERM surcharge was eliminated in February 2010, since the previous balance of deferred power costs had been recovered. During 2011, actual power supply costs were below the amount included in base retail rates in both Washington and Idaho. This was due to improved hydroelectric generation and lower purchased power and fuel costs. As such, we deferred $4.2 million in Idaho and $12.8 million in Washington for potential future rebate to customers.

Fuel for generation decreased $57.8 million primarily due to a decrease in thermal generation. This was due in part to an increase in hydroelectric generation.

Other fuel costs increased $50.0 million. This 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 associated revenues are reflected as sales of fuel.

The expense for natural gas purchased increased $9.7 million due to an increase in total therms purchased (increased costs $31.0 million), partially offset by a decrease in the price of natural gas (decreased costs $21.3 million). Total therms purchased increased due to an increase in retail loads (resulting from colder weather in the heating season) and an increase in wholesale sales with the balancing of loads and resources as part of the natural gas procurement and resource optimization process. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs. During

2011, natural gas resource costs were reduced by $10.0 million reflecting the rebate of a deferred liability for natural gas costs through the purchased gas adjustments.

2010 compared to 2009

Net income for Avista Utilities was $86.7 million for 2010 and 2009. Avista Utilities income from operations was $208.1 million for 2010 compared to $195.4 million for 2009. The increase in income from operations was primarily due to an increase in gross margin (operating revenues less resource costs) and a decrease in taxes other than income taxes, partially offset by an increase in other operating expenses and depreciation and amortization.

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	
	2010	2009	2010	2009	2010	2009	2010	2009
Operating revenues	$ 974,283	$ 840,783	$ 511,249	$ 554,418	$ (65,886)	$	$ 1,419,646	$ 1,395,201
Resource costs	479,252	379,058	381,709	420,481	(65,886)		795,075	799,539
Gross margin	$ 495,031	$ 461,725	$ 129,540	$ 133,937	$	$	$ 624,571	$ 595,662

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Avista Utilities   operating revenues increased $24.4 million and resource costs decreased $4.5 million, which resulted in an increase of $28.9 million in gross margin. The gross margin on electric sales increased $33.3 million and the gross margin on natural gas sales decreased $4.4 million. The increase in electric gross margin was due to general rate increases and power supply costs below the amount included in base retail rates in Washington, partially offset by warmer weather (during the heating season) that reduced retail loads. The decrease in our natural gas gross margin was primarily due to warmer weather that reduced retail loads, partially offset by general rate increases.

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). The magnitude of these transactions in prior years was immaterial, but increased significantly in 2010 with the addition of the natural gas-fired Lancaster Plant to our electric resource mix.

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	
	2010	2009	2010	2009
Residential	$ 296,627	$ 315,649	3,618	3,791
Commercial	265,219	273,954	3,100	3,177
Industrial	114,792	107,741	2,099	1,948
Public street and highway lighting	6,702	6,607	26	26
Total retail	683,340	703,951	8,843	8,942
Wholesale	165,553	88,414	3,803	2,354
Sales of fuel	106,375	32,992		
Other	19,015	15,426		
Total	$ 974,283	$ 840,783	12,646	11,296

Retail electric revenues decreased $20.6 million due to a decrease in total MWhs sold (decreased revenues $7.5 million) primarily due to a decrease in use per customer as a result of warmer weather in the heating season, and a decrease in revenue per MWh (decreased revenues $13.1 million). Compared to 2009, residential electric use per customer was down 5 percent and commercial use per customer decreased 3 percent. The decrease in revenue per MWh was primarily due to the elimination of the ERM surcharge in February 2010, partially offset by the Washington and Idaho general rate increases. The decrease in revenue per MWh was also due to a greater percentage of revenue derived from industrial customers.

Wholesale electric revenues increased $77.1 million due to an increase in sales prices (increased revenues $14.0 million) and an increase in sales volumes (increased revenues $63.1 million). The increase in sales volumes primarily related to increased resource optimization activities and lower than expected retail sales.

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market rather than operate the generating units. Sales of fuel increased $73.4 million due to an increase in thermal generation resource optimization activities in 2010 as compared to 2009. In 2010, $24.7 million of these sales were made to our natural gas operations and are reflected as intracompany revenues and resource costs.

The net margin on wholesale sales and sales of fuel is applied to reduce or increase resource costs as accounted for under the ERM (no deferrals for 2010) and the PCA mechanism.

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

	Natural Gas Operating Revenues		Natural Gas Therms Delivered	
	2010	2009	2010	2009
Residential	$ 193,169	$ 251,022	188,546	207,979
Commercial	98,257	135,236	113,422	126,345
Interruptible	2,738	4,709	4,443	5,360
Industrial	3,756	5,236	5,312	5,558
Total retail	297,920	396,203	311,723	345,242
Wholesale	197,364	143,524	468,887	397,977
Transportation	6,470	6,067	142,093	144,580
Other	9,495	8,624	393	502
Total	$ 511,249	$ 554,418	923,096	888,301

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Retail natural gas revenues decreased $98.3 million due to lower retail rates (decreased revenues $66.2 million) and volumes (decreased revenues $32.0 million). We sold less retail natural gas in 2010 as compared to 2009 primarily due to warmer weather. Compared to 2009, residential natural gas use per customer was down 10 percent and commercial use per customer decreased 11 percent. The decrease in retail rates reflects purchased gas adjustments, partially offset by general rate increases.

Wholesale natural gas revenues increased $53.8 million due to an increase in prices (increased revenues $24.0 million) and volumes (increased revenues $29.8 million). We plan for sufficient natural gas capacity to serve our retail customers on a theoretical peak day. As such, we generally have more pipeline and storage capacity than what is needed. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs. With lower retail loads in 2010 as compared to 2009, we had more opportunity to optimize transportation resources. We hedge against expected natural gas volumes with forward purchases. In some situations, customer demand is below the amount hedged and we sell natural gas in excess of load requirements. Part of the increase in the volume of wholesale natural gas sales reflects lower than expected retail loads in 2010 and the sale of excess natural gas purchased. In 2010, $41.2 million of these sales were made to our electric generation operations and are reflected as intracompany revenues and resource costs. Differences between revenues and costs from sales of resources in excess of retail load requirements and from resource optimization are accounted for through the PGA mechanisms.

The following table presents our average number of electric and natural gas retail customers for the year ended December 31:

	Electric Customers		Natural Gas Customers	
	2010	2009	2010	2009
Residential	315,283	313,884	282,721	280,667
Commercial	39,489	39,276	33,431	33,214
Interruptible			38	42
Industrial	1,376	1,394	254	258
Public street and highway lighting	449	444		
Total retail customers	356,597	354,998	316,444	314,181

The following table presents our utility resource costs for the year ended December 31 (dollars in thousands):

	2010	2009
Electric resource costs:		
Power purchased	$ 186,312	$ 193,683
Power cost amortizations, net	2,798	31,102
Fuel for generation	142,154	89,602
Other fuel costs	114,211	31,881
Other regulatory amortizations, net	17,772	19,602
Other electric resource costs	16,005	13,188
Total electric resource costs	479,252	379,058
Natural gas resource costs:		
Natural gas purchased	386,828	389,034
Natural gas cost amortizations, net	(18,741)	20,256

Other regulatory amortizations, net	13,622	11,191
Total natural gas resource costs	381,709	420,481
Intracompany resource costs	(65,886)	
Total resource costs	$ 795,075	$ 799,539

Power purchased decreased $7.4 million due to a decrease in wholesale prices (decreased costs $38.9 million), partially offset by an increase in the volume of power purchases (increased costs $31.5 million). The increase in volumes was primarily due to purchasing power to cover for below normal hydroelectric generation, the purchased power agreement for the Lancaster Plant and an increase in wholesale sales volumes related to optimization.

Net amortization of deferred power costs was $2.8 million for 2010 compared to $31.1 million for 2009. During 2010, we recovered (collected as revenue) $6.8 million of previously deferred power costs in Washington and $13.0 million in Idaho. The Washington ERM surcharge was eliminated in February 2010, since the previous balance of deferred power costs had been recovered. During 2010, we deferred $9.8 million of power costs in Idaho, as power supply costs exceeded the amount included in base retail rates. In Washington, we deferred $6.8 million of costs (included in other regulatory assets) associated with the Lancaster Project. This was the maximum deferral for 2010 as agreed to in the Washington general rate case settlement. In that settlement, the parties agreed that there would not be any deferrals under the ERM for 2010. The net effect of the settlement for the Lancaster Plant deferrals and the ERM was slightly positive to 2010 earnings.

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Fuel for generation increased $52.6 million primarily due to an increase in thermal generation, including fuel for the Lancaster Plant. In 2009, we experienced an outage at Colstrip, which reduced thermal generation.

Other fuel costs increased $82.3 million. This 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 associated revenues are reflected as sales of fuel.

The expense for natural gas purchased decreased $2.2 million due to a decrease in the price of natural gas (decreased costs $20.7 million), partially offset by an increase in the total therms purchased (increased costs $18.5 million). Total therms purchased increased due to wholesale sales with the balancing of loads and resources as part of the natural gas procurement and optimization process, partially offset by decreased retail sales volumes. We engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas to generate economic value that offsets net natural gas costs. During 2010, natural gas resource costs were reduced by $18.7 million reflecting the rebate of a deferred liability for natural gas costs through the purchased gas adjustments implemented in November 2009.

Ecova

2011 compared to 2010

Ecova s net income attributable to Avista Corp. was $9.7 million for 2011 compared to $7.4 million for 2010. Operating revenues increased $35.8 million and total operating expenses increased $30.8 million. The increase in operating revenues was primarily due growth in energy management and expense management services, as well as the acquisition of Loyalton effective December 31, 2010, which added $8.5 million to 2011 operating revenues. Ecova s organic revenue growth was approximately 13 percent from 2010 to 2011. The increase in operating expenses primarily reflects increased costs necessary for business growth and the acquisition of Loyalton. During the fourth quarter of 2011, Ecova determined that certain revenues, which had previously been reported net of expenses, should be reported on a gross basis. This increased operating revenues and expenses by $9.2 million with no impact to net income for 2011. As of December 31, 2011, Ecova had 645 expense management customers representing 497,000 billed sites in North America. In 2011, Ecova managed bills totaling $18.3 billion, an increase of $1.0 billion as compared to 2010.

2010 compared to 2009

Ecova s net income attributable to Avista Corporation was $7.4 million for 2010 compared to $5.3 million for 2009. Operating revenues increased $24.8 million and operating expenses increased $20.5 million. The increase in net income attributable to Avista Corporation, operating revenues and expenses was primarily due to the third quarter 2009 acquisition of Ecos, as well as moderate growth in expense management and energy management services. The increase in operating expenses was also due to the amortization of intangible assets from the acquisition of Ecos. As of December 31, 2010, Ecova had 534 expense management customers representing 361,000 billed sites in North America. The decrease in billed sites at year-end 2010 as compared to year-end 2009 billed sites of 421,000 was due to the loss of a customer that had a significant number of billed sites, but represented only approximately 1 percent of annual revenues. In 2010, Ecova managed bills totaling $17.3 billion, a decrease of $0.1 billion as compared to 2009. This decrease was primarily due to a decrease in the average value of each bill processed.

Other Businesses

2011 compared to 2010

The net loss from these operations was $0.3 million for 2011 compared to $1.7 million for 2010. Operating revenues decreased $20.7 million and total operating expenses decreased $20.2 million. The decrease in operating revenues and operating expenses was primarily due to the assignment of the Lancaster PPA to Avista Corp. in December 2010. Earnings from METALfx increased to $1.4 million for 2011 compared to $0.8 million for 2010. Losses on investments were $0.5 million for 2011 compared to losses of $3.3 million for 2010. The loss for 2010 included a $2.2 million impairment of our investment in a fuel cell business.

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2010 compared to 2009

The net loss attributable to Avista Corporation from these operations was $1.7 million for 2010 compared to $5.0 million for 2009. Operating revenues increased $21.0 million, operating expenses increased $8.4 million, and interest expense increased $5.3 million. The increase in operating revenues, operating expenses and interest expense was primarily due to the consolidation of Spokane Energy effective January 1, 2010, which had no impact on the net loss attributable to Avista Corporation. The improvement in results for these businesses in 2010 was due in part to increased earnings at METALfx, which had net income of $0.8 million for 2010, compared to $0.2 million for 2009. We also had decreased litigation costs related to the remaining contracts and previous operations of Avista Energy. Losses on long-term investments were $3.3 million for 2010 compared to $0.8 million for 2009. In 2009, we recorded an impairment of a commercial building of $3.0 million.

Accounting Standards to be Adopted in 2012

At this time, we are not expecting the adoption of accounting standards to have a material impact on our financial condition, results of operations and cash flows in 2012. For information on accounting standards adopted in 2011 and earlier periods, refer to Note 2 of the Notes to Consolidated Financial Statements.

Critical Accounting Policies and Estimates

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

Avista Utilities Operating Revenues

Operating revenues for our utility business related to the sale of energy are generally recorded when service is rendered or energy is delivered to our customers. The determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, we estimate the amount of energy delivered to customers since the date of the last meter reading and the corresponding unbilled revenue is estimated and recorded. Our estimate of unbilled revenue is based on:

- the number of customers,
- current rates,
- meter reading dates,
- actual native load for electricity, and
- actual throughput for natural gas.

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

Regulatory Accounting

We prepare our consolidated financial statements in accordance with regulatory accounting practices. This requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) be reflected as deferred charges on our Consolidated Balance Sheets and are not reflected in our Consolidated Statements of Income until the period during which matching revenues are recognized. We expect to recover our regulatory assets through future rates. Our regulatory assets are subject to review for prudence and recoverability. As such, certain deferred costs may be disallowed by our regulators. If at some point in the future we determine that we no longer meet the criteria for continued application of regulatory accounting for all or a portion of our regulated operations, we could be:

- required to write off regulatory assets, and

- precluded from the future deferral of costs not recovered through rates when such costs are incurred, even if we expect to recover such costs in the future.

Utility Energy Commodity Derivative Assets and Liabilities

Our utility enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of our management of loads and resources and certain contracts are considered derivative instruments. The WUTC and the IPUC issued accounting orders authorizing us to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for us to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Consolidated Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases. We use quoted market prices and forward price curves to estimate the fair value of our utility derivative commodity instruments. As such, the fair value of utility derivative commodity instruments recorded on our Consolidated Balance Sheets is sensitive to market price fluctuations that can occur on a daily basis.

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Pension Plans and Other Postretirement Benefit Plans

We have a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities.

Our Finance Committee of the Board of Directors:

- establishes investment policies, objectives and strategies that seek an appropriate return for the pension plan, and
- reviews and approves changes to the investment and funding policies.

We have contracted with an investment consultant who is responsible for managing/monitoring the individual investment managers. The investment managers performance and related individual fund performance is reviewed at least quarterly by an internal benefits committee and by the Finance Committee to monitor compliance with our established investment policy objectives and strategies.

Our pension plan assets are invested primarily in marketable debt and equity securities. Pension plan assets may also be invested in real estate, absolute return, venture capital/private equity and commodity funds. In seeking to obtain the desired return to fund the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established investment allocation percentages by asset classes as disclosed in Note 10 of the Notes to Consolidated Financial Statements.

We also have a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to our executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans.

Pension costs (including the SERP) were $23.9 million in 2011, $21.3 million for 2010 and $25.8 million for 2009. Of our pension costs, approximately 65 percent are expensed and 35 percent are capitalized consistent with labor charges. The costs related to the SERP are expensed. Our costs for the pension plan are determined in part by actuarial formulas that are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension costs are affected by:

- employee demographics (including age, compensation and length of service by employees),
- the amount of cash contributions we make to the pension plan, and
- the return on pension plan assets.

Changes made to the provisions of our pension plan may also affect current and future pension costs. Pension plan costs may also be significantly affected by changes in key actuarial assumptions, including the:

- expected return on pension plan assets,
- discount rate used in determining the projected benefit obligation and pension costs, and
- assumed rate of increase in employee compensation.

The change in pension plan obligations associated with these factors may not be immediately recognized as pension costs in our Consolidated Statement of Income, but we generally recognize the change in future years over the remaining average service period of pension plan participants. As such, our costs recorded in any period may not reflect the actual level of cash benefits provided to pension plan participants.

We have not made any changes to pension plan provisions in 2011, 2010 and 2009 that have had any significant effect on our recorded pension plan amounts. We have revised the key assumption of the discount rate in 2011, 2010 and 2009. Such changes had an effect on our pension costs in 2011, 2010 and 2009 and may affect future years, given the cost recognition approach described above. However, in determining pension obligation and cost amounts, our assumptions can change from period to period, and such changes could result in material changes to our future pension costs and funding requirements.

In selecting a discount rate, we consider yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits. In 2011, we decreased the pension plan discount rate to 5.05 percent from 5.70 percent in 2010. We used a discount rate of 6.30 percent in 2009. This increased the projected benefit obligation by approximately $40 million in 2011 and $31 million in 2010.

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The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by our plan. We used an expected long-term rate of return of 7.40 percent in 2011, 7.75 percent in 2010 and 8.5 percent in 2009. This increased pension costs by approximately $1.1 million in 2011 and by approximately $2.0 million in 2010. The actual return on plan assets, net of fees, was a gain of $14.7 million (or 4.7 percent) for 2011, a gain of $29.8 million (or 10.8 percent) for 2010 and a gain of $50.1 million (or 24.4 percent) for 2009. We periodically analyze the estimated long-term rate of return on assets based upon revisions to the investment portfolio.

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

Actuarial Assumption	Change in Assumption	Effect on Projected Benefit Obligation	Effect on Pension Cost
Expected long-term return on plan assets	-0.5%	$ *	$ 1,562
Expected long-term return on plan assets	+0.5%	*	(1,562)
Discount rate	-0.5%	34,791	2,897
Discount rate	+0.5%	(31,072)	(2,616)

* Changes in the expected return on plan assets would not have an effect on our total pension liability.

We provide certain health care and life insurance benefits for substantially all of our retired employees. We accrue the estimated cost of postretirement benefit obligations during the years that employees provide service. Assumed health care cost trend rates have a significant effect on the amounts reported for our postretirement plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase our accumulated postretirement benefit obligation as of December 31, 2011 by $14.8 million and the service and interest cost by $0.8 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease our accumulated postretirement benefit obligation as of December 31, 2011 by $12.3 million and the service and interest cost by $0.7 million.

Contingencies

We have unresolved regulatory, legal and tax issues for which there is inherent uncertainty for the ultimate outcome of the respective matter. We accrue a loss contingency if it is probable that an asset is impaired or a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. We also disclose losses that do not meet these conditions for accrual, if there is a reasonable possibility that a loss may be incurred.

For all material contingencies, we have made a judgment as to the probability of a loss occurring and as to whether or not the amount of the loss can be reasonably estimated. If the loss recognition criteria are met, liabilities are accrued or assets are reduced. However, no assurance can be given to the ultimate outcome of any particular contingency.

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Liquidity and Capital Resources

Review of Cash Flow Statement

Overall During 2011, positive cash flows from operating activities of $269.5 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $239.8 million and dividends of $63.7 million. In December 2011, we issued $85.0 million of long-term debt. The net proceeds from the issuance of debt were used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit. In total on a consolidated basis, we were able to reduce short-term borrowings by $14.0 million during 2011.

Operating Activities Net cash provided by operating activities was $269.5 million for 2011 compared to $228.4 million for 2010. Net cash used in working capital components was $14.9 million for 2011, compared to $20.8 million for 2010. The net cash used during 2011 primarily reflects negative cash flows from other current assets (primarily related to an increase in deposits with counterparties), net cash outflows related to accounts payable and an increase in natural gas stored. These negative cash flows were partially offset by net cash inflows related to accounts receivable.

The net cash used during 2010 primarily reflects negative cash flows from accounts receivable (representing an increase in receivables outstanding at Avista Utilities and Ecova), and an increase in materials and supplies, fuel stock and natural gas stored. These negative cash flows were partially offset by net cash inflows related to accounts payable.

Net amortization of deferred power and natural gas costs was $21.9 million for 2011 compared to net deferrals of $9.8 million for 2010. The provision for deferred income taxes was $24.0 million for 2011 compared to $37.7 million for 2010. Contributions to our defined benefit pension plan were $26.0 million for 2011 compared to $21.0 million for 2010. Cash paid for interest decreased to $69.1 million for 2011, compared to $74.2 million for 2010.

Investing Activities Net cash used in investing activities was $282.3 million for 2011, an increase compared to $253.2 million for 2010. Utility property capital expenditures increased by $37.6 million for 2011 as compared to 2010. At the end of 2011, the majority of Ecova s funds held for clients were held as securities available for sale (purchases of $96.6 million). In 2010, the funds held for clients were in money market funds. The net cash paid by subsidiaries for acquisitions in 2011 of $31.4 million primarily represents Ecova s acquisition of Prenova.

Financing Activities Net cash provided by financing activities was $18.1 million for 2011 compared to net cash provided of $57.2 million for 2010. During 2011, short-term borrowings on Avista Corp. s committed line of credit decreased $49.0 million. Borrowings on Ecova s committed line of credit increased $35.0 million and these proceeds were used to fund the acquisition of Prenova. Cash dividends paid increased to $63.7 million (or $1.10 per share) for 2011 from $55.7 million (or $1.00 per share) for 2010. We issued $26.5 million of common stock during 2011, including $19.5 million under a sales agency agreement. We cash settled interest rate swap agreements for $10.6 million related to the pricing of $85.0 million of long-term debt issued in December 2011. Customer fund obligations at Ecova increased $17.8 million.

During 2010, our short-term borrowings increased $23.0 million due to a net increase in the amount of debt outstanding under our committed line of credit. In December 2010, we issued $137.0 million (net proceeds of $136.4 million) of long-term debt. A portion of the proceeds were used to redeem $75.0 million of long-term debt scheduled to mature in 2013. In conjunction with the redemption of long-term debt, we paid a make-whole redemption premium of $10.7 million. We issued $46.2 million of common stock during 2010, including $43.2 million under a sales agency agreement.

Overall Liquidity

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

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

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

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

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

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

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

As of December 31, 2011, we had $310.0 million of available liquidity under our committed line of credit. With our $400.0 million credit facility that expires in February 2017, we believe that we have adequate liquidity to meet our needs for the next 12 months.

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

Credit and Nonperformance Risk

Our contracts for the purchase and sale of energy commodities can require collateral in the form of cash or letters of credit. As of December 31, 2011, we had cash deposited as collateral of $18.2 million and letters of credit of $18.8 million outstanding related to our energy derivative contracts. Price movements and/or a downgrade in our credit ratings may impact further the amount of collateral required. See Credit Ratings for further information. For example, in addition to limiting our ability to conduct transactions, if our credit ratings were lowered to below investment grade and energy prices decreased by 15 percent in the first year and 20 percent in subsequent years, we estimate, based on our positions outstanding at December 31, 2011, that we would potentially be required to post additional collateral of up to $147 million. The additional collateral amount is higher than the amount disclosed in Note 6 of the Notes to Consolidated Financial Statements because this analysis includes contracts that are not considered derivatives and due to the assumptions about potential energy price changes.

Under the terms of interest rate swap agreements that we enter into periodically, we may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the instrument. This has not historically been significant to our liquidity position. As of December 31, 2011, we had interest rate swap agreements outstanding with a notional amount totaling $160 million and we had posted collateral of $4.2 million ($1.5 million in cash and $2.7 million in the form of a letter of credit). If our credit ratings were lowered to below investment grade based on our interest rate swap agreements outstanding at December 31, 2011, we would potentially be required to post additional collateral of up to $4.6 million.

Dodd-Frank Wall Street Reform and Consumer Protection Act

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted into law in July 2010. The Dodd-Frank Act establishes regulatory jurisdiction by the Commodity Futures Trading Commission (CFTC) and the Securities and Exchange Commission (SEC) for certain swaps (which include a variety of derivative instruments) and the users of such swaps, that previously had been largely exempted from regulation.

A variety of rules must be adopted by federal agencies (including the CFTC, SEC and the FERC) to implement the Dodd-Frank Act. These rules being developed and implemented will clarify the impact of the Dodd-Frank Act on Avista Corp., which may be significant.

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Under the Dodd-Frank Act, Swap Dealers and Major Swap Participants generally will be required to collect minimum initial and variation margin from their counterparties for non-cleared swaps. However the requirement varies with the type of counterparty and the regulator of the Major Swap Participant or Swap Dealer. Avista Corp. should be categorized as a counterparty that is a non-financial end user for the purposes of the Dodd-Frank Act, i.e., as a non-financial entity that engages in derivatives to hedge commercial risk. Under a proposed rule issued by the CFTC, swap dealers and major swap participants subject to regulation by the CFTC would not be required to collect initial or variation margin from counterparties that are non-financial end users. The SEC has not yet issued a proposed rule with respect to security-based swap dealers or security-based major swap participants. However, notwithstanding levels of margin required by regulation (or the lack thereof), concern remains that swap dealer and major swap participant counterparties will pass along their increased capital and interdealer margin costs through higher prices and reductions in thresholds for posting.

The Dodd-Frank Act also requires certain swaps to be cleared and traded on exchanges or swap execution facilities. Such clearing requirements would result in a significant change from our current practice of bilaterally negotiated credit terms. An exemption to mandatory clearing is available under the Dodd-Frank Act for counterparties that are non-financial end users using swaps to hedge commercial risk. However, the cost of entering into a non-cleared swap that is available as a cleared swap may be greater and margin levels are expected to be higher.

We will continue to monitor developments including certain proposals to delay various implementation steps defined in the Act. We cannot predict the impact the Dodd-Frank Act may ultimately have on our operations.

Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, and excluding noncontrolling interests, consisted of the following as of December 31, 2011 and 2010 (dollars in thousands):

	December 31, 2011		December 31, 2010	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 7,474	0.3%	$ 358	%
Current portion of nonrecourse long-term debt	13,668	0.5	12,463	0.5
Short-term borrowings	96,000	3.8	110,000	4.5
Long-term debt to affiliated trusts	51,547	2.0	51,547	2.1
Nonrecourse long-term debt	32,803	1.3	46,471	1.9
Long-term debt	1,169,826	45.7	1,101,499	45.0
Total debt	1,371,318	53.6	1,322,338	54.0
Total Avista Corporation stockholders equity	1,185,701	46.4	1,125,784	46.0
Total	$ 2,557,019	100.0%	$ 2,448,122	100.0%

We need to finance capital expenditures and acquire additional funds for operations from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduces the amount of cash flow available to fund capital expenditures, purchased power, fuel and natural gas costs, dividends and other requirements. Our stockholders equity increased $59.9 million during 2011 primarily due to net income and the issuance of common stock, partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities, as well as issuances of long-term debt and common stock, are expected to be the primary source of funds for operating needs, dividends and capital expenditures for 2012. Borrowings under our $400.0 million committed line of credit will supplement these funds to the extent necessary.

We are planning to issue up to $45 million of common stock in 2012 in order to maintain our capital structure at an appropriate level for our business. In 2011, we issued $26.5 million of common stock, including $19.5 million under a sales agency agreement. As of December 31, 2011, we had 0.2 million shares available to be issued under this agreement and we expect to expand this agreement for a significant portion of our 2012 common stock issuances.

In December 2011, we issued $85.0 million of 4.45 percent First Mortgage Bonds due in 2041. The net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under our $400.0 million committed line of credit. We expect to issue up to $100.0 million of long-term debt in 2012.

In February 2011, we entered into a new committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2015 that replaced our $320.0 million and $75.0 million committed lines of credit that had expiration dates in April 2011. In December 2011, this committed line of credit was amended to extend the expiration date to February 2017 and improve the pricing terms.

Our committed line of credit agreement 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, 2011, we were in compliance with this covenant with a ratio of 53.6 percent.

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Balances outstanding and interest rates of borrowings (excluding letters of credit) under our committed lines of credit were as follows as of and for the years ended December 31 (dollars in thousands):

	2011	2010	2009
Balance outstanding at end of year	$ 61,000	$ 110,000	$ 87,000
Letters of credit outstanding at end of year	$ 29,030	$ 27,126	$ 28,448
Maximum balance outstanding during the year	$ 130,000	$ 170,000	$ 275,000
Average balance outstanding during the year	$ 74,947	$ 80,230	$ 186,474
Average interest rate during the year	1.43%	0.60%	0.65%
Average interest rate at end of year	1.12%	0.57%	0.59%

Any default on the line of credit or other financing arrangements of Avista Corp. or any of our significant subsidiaries could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. Avista Corp. does not guarantee the indebtedness of any of its subsidiaries. As of December 31, 2011, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements.

As part of its cash management practices and operations, Ecova and Avista Corp. entered into a master promissory note in January 2012, where Ecova will from time to time make unsecured short-term loans to Avista Corp. The master promissory note limits the total outstanding indebtedness to no more than $50.0 million in principal. Additionally, such loans are required to be repaid on the last business day of each quarter (March, June, September and December) and sooner upon demand by Ecova. Amounts are loaned at a rate consistent with Avista Corp. s credit facility.

We are restricted under our Restated Articles of Incorporation as to the additional preferred stock we can issue. As of December 31, 2011, we could issue $835.2 million of additional preferred stock at an assumed dividend rate of 8.5 percent. We are not planning to issue preferred stock.

Under the Mortgage and Deed of Trust securing our First Mortgage Bonds (including Secured Medium-Term Notes), we may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of:

- 66-2/3 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or

- an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or

- deposit of cash.

However, we may not issue any additional First Mortgage Bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless our net earnings (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2011, our property additions and retired bonds would have allowed us to issue $727.1 million in aggregate principal amount of additional First Mortgage Bonds. We believe that we have adequate capacity to issue First Mortgage Bonds to meet our financing needs over the next several years.

Avista Utilities Capital Expenditures

Capital expenditures for our utility were $647.4 million for the years 2009 through 2011. We expect utility capital expenditures to be about $250 million for each of 2012, 2013 and 2014. Our capital budget for 2012 includes the following (dollars in millions):

Transmission and distribution	$ 78
Information technology	44
Customer growth	37
Generation	31
Natural gas	23
Facilities	18
Environmental	9
Other	17
Total	$ 257

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These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements.

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

Ecova Credit Agreement

In April 2011, Ecova entered into a new $40.0 million three-year committed line of credit agreement with a financial institution that replaced its $15.0 million committed credit agreement that had an expiration date of May 2011. In December 2011, the amount of this committed line of credit was increased to $60.0 million, which is scheduled to decrease to $55.0 million on September 30, 2012 and $50.0 million on December 31, 2012. Ecova expects to expand this facility in 2012. The credit agreement is secured by substantially all of Ecova s assets. There were $35.0 million of borrowings outstanding under Ecova s credit agreement as of December 31, 2011. The proceeds from these borrowings were used to fund the acquisition of Prenova in November 2011. Ecova borrowed $25.0 million under this committed line of credit to fund a portion of the acquisition of LPB in January 2012.

Ecova Redeemable Stock

In 2007, Ecova amended its employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Ecova providing the shares are held for a minimum of six months. Stock is reacquired at fair market value at the date of reacquisition. As the repurchase feature is at the discretion of the minority shareholders and option holders, there were redeemable noncontrolling interests of $12.9 million as of December 31, 2011 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock. In 2009, the Ecova employee stock incentive plan was amended such that, on a prospective basis, not all options granted under the plan have the put right. Additionally, there were redeemable noncontrolling interests of $38.9 million related to the Cadence Network acquisition, as the previous owners can exercise a right to put their stock back to Ecova in July 2011 or July 2012 if Ecova is not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised in July 2011. These redemption rights expire July 31, 2012. Should the previous owners of Cadence Network exercise their redemption rights, Ecova will seek the necessary funding through its credit facility, a capital request from existing owners, an infusion of capital from potential new investors or a combination of these sources. In January 2011, Avista Capital purchased shares held by one of the previous owners of Cadence Network for $5.6 million.

Off-Balance Sheet Arrangements

As of December 31, 2011, we had $29.0 million in letters of credit outstanding under our $400.0 million committed line of credit, an increase from $27.1 million as of December 31, 2010.

Pension Plan

As of December 31, 2011, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. The pension plan funding deficit increased in 2011 primarily due to a decrease in the discount rate as well as market returns on assets that were lower than the expected long-term return on plan assets. We contributed $26 million to the pension plan in 2011. We expect to contribute a total of $176 million (or $44 million per year) to the pension plan in the period 2012 through 2015. The final determination of pension plan contributions for future periods is subject to multiple variables, most of which are beyond our control, including further changes to the fair value of pension plan assets and changes in actuarial assumptions (in particular the discount rate used in determining the benefit obligation).

Credit Ratings

Our access to capital markets and our cost of capital are directly affected by our credit ratings. In addition, many of our contracts for the purchase and sale of energy commodities contain terms dependent upon our credit ratings. See Credit and Nonperformance Risk and Note 6 of the Notes to Consolidated Financial Statements. The following table summarizes our credit ratings as of February 28, 2012:

	Standard & Poor s (1)	Moody s (2)
Corporate/Issuer rating	BBB	Baa2
Senior secured debt	A-	A3
Senior unsecured debt	BBB	Baa2

(1) Standard & Poor s lowest level of investment grade credit rating is BBB-.
(2) Moody s lowest level of investment grade credit rating is Baa3.

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

Dividends

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

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

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

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock (when outstanding) contained in our Restated Articles of Incorporation, as amended.

In February 2012, Avista Corp. s Board of Directors declared a quarterly dividend of $0.29 per share on the Company s common stock. This was an increase of $0.015 per share, or 5 percent from the previous quarterly dividend of $0.275 per share.

Contractual Obligations

The following table provides a summary of our future contractual obligations as of December 31, 2011 (dollars in millions):

	2012	2013	2014	2015	2016	Thereafter
Avista Utilities:						
Long-term debt maturities	$ 7	$ 50	$	$	$	$ 1,127
Long-term debt to affiliated trusts						52
Interest payments on long-term debt (1)	65	64	63	63	63	648
Short-term borrowings	61					
Energy purchase contracts (2)	353	260	227	189	166	1,677
Public Utility District contracts (2)	3	3	3	3	3	45
Operating lease obligations (3)	1	1	1			2
Other obligations (4)	29	30	31	28	33	247
Information services contracts	13	11	8	7	7	7
Pension plan funding (5)	44	44	44	44		
Spokane Energy:						
Nonrecourse long-term debt maturities	14	15	16	1		
Interest payments on nonrecourse long-term debt	3	2	1			

Avista Capital (consolidated):						
Redeemable noncontrolling interests (6)	52					
Short-term borrowings	35					
Venture funds investments (7)	2	1				
Operating lease obligations (3)	4	4	4	2	1	2
Total contractual obligations	$ 686	$ 485	$ 398	$ 337	$ 273	$ 3,807

(1) Represents our estimate of interest payments on long-term debt, which is calculated based on the assumption that all debt is outstanding until maturity. Interest on variable rate debt is calculated using the rate in effect at December 31, 2011.

(2) Energy purchase contracts were entered into as part of the obligation to serve our retail electric and natural gas customers energy requirements. As a result, costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost adjustment mechanisms.

(3) Includes the interest component of the lease obligation. Future capital lease obligations are not material.

(4) Represents operational agreements, settlements and other contractual obligations for our generation, transmission and distribution facilities. These costs are generally recovered through base retail rates.

(5) Represents our estimated cash contributions to the pension plan through 2015. We cannot reasonably estimate pension plan contributions beyond 2015 at this time.

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(6) Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Ecova common stock redeemed by Ecova during July 2011 or July 2012 if Ecova is not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised in July 2011. These redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Ecova at the time of the redemption election as determined by certain independent parties. In addition, certain shares acquired under Ecova s employee stock incentive plan are redeemable at the option of the shareholder.

(7) Represents a commitment to fund a limited partnership venture fund commitment made by a subsidiary of Avista Capital.

These contractual obligations do not include income tax payments.

In addition to the contractual obligations disclosed above, we will incur additional operating costs and capital expenditures in future periods for which we are not contractually obligated as part of our normal business operations.

Competition

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

In retail markets, we compete with various rural electric cooperatives and public utility districts in and adjacent to our service territories in the provision of service to new electric customers. Alternate providers of energy may also compete with us for sales to existing customers. Similarly, our natural gas distribution operations compete with other energy sources including heating oil, propane and other fuels.

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

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

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

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

These wholesale markets are regulated by the FERC, which requires electric utilities to:

- transmit power and energy to or for wholesale purchasers and sellers,
- enlarge or construct additional transmission capacity for the purpose of providing these services, and
- transparently price and offer transmission services without favor to any party, including the merchant functions of the utility.

Participants in the wholesale energy markets include:

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

Ecova is subject to competition for service to existing customers and as they develop products and services and enter new markets. Competition from other companies may mean challenges for Ecova to be the first to market a new product or service to gain an advantage in market share. Other challenges for Ecova include the availability of funding and resources to meet capital needs, and rapidly advancing technologies which require continual product enhancement to avoid obsolescence.

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Economic Conditions and Utility Load Growth

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

Economic growth in the region we serve has slowed significantly since it peaked five years ago, yet we continue to experience customer growth. We have three distinct metropolitan areas in our service area: Spokane, Washington, Coeur d Alene, Idaho and Medford, Oregon; and we are tracking three separate economic indicators which impact our business: employment change, unemployment rates and foreclosure rates. We have observed mixed results during the economic downturn. The December 2011 employment indicators are negative except for Medford, unemployment rates are lower in all three areas and foreclosure rates have decreased compared to early periods. Compared to the U.S. the economy in our service area is broadly weaker than the national average. We expect the economy in our service area to underperform compared to the U.S. in 2012.

Employment in our eastern Washington and northern Idaho service area recently has reversed the gains seen early in 2011, but our southwestern Oregon service area has stabilized. Non-farm employment growth for 2011 was 0.1 percent in Medford, Oregon with large gains in hospitality, health services and retail trade offset by large declines in government. We observed employment declines of 1.3 percent in the Spokane area with losses in professional services and government, partially offset by gains in manufacturing. Employment declined by 2.1 percent in Coeur d Alene, Idaho largely due to government job reductions. The U.S. nonfarm sector jobs grew by 1.3 percent in the same twelve-month period.

The unemployment rate went down in December 2011 from the year earlier level in Spokane, Medford, and Coeur d Alene. The Spokane rate was 9.1 percent in December 2010 but declined to 9.0 percent in December 2011. Medford declined from 11.6 percent to 10.3 percent while Coeur d Alene went from 10.8 percent to 9.8 percent. The U.S. rate declined from 9.1 percent to 8.3 percent in the same period.

The housing market in our service area has improved when measured by foreclosure rates, with two of our three metropolitan areas better than the national average. The December 2011 national rate was 0.16 percent with a higher than national average level at 0.19 percent in Jackson County, Oregon. The Spokane housing market was 0.06 percent and Kootenai County, Idaho was 0.09 percent and both were less than half the levels experienced a year ago.

Based on our forecast for electric customer growth to average 0.7 to 1.2 percent per year and natural gas customer growth to average 1.1 to 2.1 percent within our service area, we anticipate retail electric and natural gas load growth will average between 0.7 and 1.9 percent annually for the four-year period 2012-2015. We anticipate customer and load growth at the lower end of the range in 2012 and an economic recovery and modest recovery-trend growth as the economy strengthens during the four-year period. While the number of electric and natural gas customers is growing, the average annual usage by each residential customer has not changed significantly. Electric and natural gas sales growth have slowed as retail prices have increased relative to historical prices and Company sponsored conservation programs have intensified. Population increases and business growth in our three-state service territory remains above the national average. Natural gas loads for space heating vary significantly with annual fluctuations in weather within our service territories.

The forward-looking statements set forth above regarding retail load growth are based, in part, upon purchased economic forecasts and publicly available population and demographic studies. The expectations regarding retail load growth are also based upon various assumptions, including:

- assumptions relating to weather and economic and competitive conditions,
- internal analysis of company-specific data, such as energy consumption patterns,

internal business plans, and

an assumption that we will incur no material loss of retail customers due to self-generation or retail wheeling.

Changes in actual experience can vary significantly from our projections.

Environmental Issues and Other Contingencies

We are subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which we have ownership interests are designed and operated in compliance with applicable environmental laws. Furthermore, we conduct periodic reviews and audits of pertinent facilities and operations to ensure compliance and to respond to or anticipate emerging environmental issues. The Company s Board of Directors has a committee to oversee environmental issues.

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We monitor legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to impact the operation and productivity of our generating plants and other assets.

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.

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

Climate Change and Greenhouse Gas Emission Reduction Initiatives

Concerns about long-term global climate changes could have a significant effect on our business. Our operations could also be affected by changes in laws and regulations intended to mitigate the risk of or alter global climate changes, including restrictions on the operation of our power generation resources and obligations imposed on the sale of natural gas. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of streamflows, which impact hydroelectric generation. Extreme weather events could increase service interruptions, outages and maintenance costs. Changing temperatures could also increase or decrease customer demand.

Greenhouse gas (GHG) emission standards could result in significant compliance costs. Such standards could also preclude us from developing, operating or contracting with certain types of generating plants.

We continue to monitor and evaluate the possible adoption of international, national, regional, or state GHG emission legislation and regulations. As the U.S. Congress has not enacted any comprehensive climate change legislation, for the foreseeable future climate change regulations are expected to emerge from the EPA and from individual states. In particular, climate change legislation was passed in the state of Washington, which includes a bill establishing GHG emissions reduction targets and another requiring that regulated sources report GHG emission from facilities that emit more than 10,000 metric tons of GHGs per year.

Although we are actively monitoring developments for climate change policies and restrictions on GHG emissions, it is important to note that we have relatively low GHG emissions as compared to other investor-owned utilities in the U.S. With 60 percent of our electric generation resource mix derived from renewable sources (including hydroelectric, biomass and contracts with wind generation projects) and a majority of our thermal generation fueled with natural gas, plus a commitment to energy efficiency, we are among the lowest carbon-emitting utilities in the nation.

Our Climate Policy Council (an interdisciplinary team of management and other employees) works to:

- facilitate internal and external communications regarding climate change issues,
- analyze policy impacts, anticipate opportunities and evaluate strategies for Avista Corp., and
- develop recommendations on climate related policy positions and action plans.

National Legislation

Climate change legislation has been proposed in the U.S. Congress; however, recent actions in the U.S. Congress indicate that climate change legislation is unlikely at this time. We continue to monitor the situation for new developments that could affect our business.

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Recent EPA Initiatives Related to Climate Change

After a public comment and review period, in December 2009, the EPA issued an endangerment finding regarding GHG emissions from motor vehicles under section 202(a) of Clean Air Act (CAA). Specifically, the EPA found that the combined emissions of GHG from new motor vehicles and new motor vehicle engines contribute to the GHG pollution which threatens public health and welfare. The EPA s findings are currently being challenged in the U.S. Court of Appeals for the District of Columbia Circuit. On April 1, 2010, the EPA and the Department of Transportation s National Highway Safety Administration announced a joint final rule establishing GHG emission standards for mobile sources. The GHG emission standards for mobile sources became effective on January 2, 2011. The EPA has concluded that the CAA requires the agency to regulate GHG emissions from stationary sources through its preconstruction and operating permit programs on the date when EPA regulations require any source (mobile or stationary) to meet GHG emission limits. In May 2010, the EPA finalized a rule establishing an applicability threshold for regulating GHG emissions from stationary sources through the preconstruction and operating permit programs.

The EPA issued a series of rules on December 23, 2010 to narrow the CAA permitting requirement so that facilities with GHG emissions below the levels set in the tailoring rule do not need permits, as well as to give the EPA authority to issue GHG permits in states that need to revise their permitting regulations to cover GHG emissions. On January 2, 2011, rules took effect requiring that permits issued under the CAA for new large stationary sources begin to address GHG emissions, as well as require Best Available Control Technology (BACT) to control these emissions. On July 20, 2011, the EPA finalized a rule that defers, for a period of three years, the GHG permitting requirements for carbon dioxide for utilities, boilers and other industrial facilities using biomass. The EPA s final decision to regulate GHG emissions from stationary sources and to establish applicability thresholds for GHGs has been challenged in the U.S. Court of Appeals for the District of Columbia.

The EPA is planning to issue regulations controlling GHG emissions from electric generating units. According to a previously announced schedule, the EPA was to propose standards for natural gas, oil and coal-fired electric generating units by September 30, 2011, and issue final standards by May 26, 2012. The EPA recently announced that it would not meet this schedule and has not yet provided a new schedule. The EPA had agreed to the original schedule as part of a settlement, as modified, with several states, local governments and environmental organizations that sued the EPA over its failure to update emissions standards for power plants and refineries as required by Section 111 of the CAA. Section 111 requires the EPA to issue New Source Performance Standards that set emissions limits for new facilities and, under certain circumstances, address emissions from existing facilities. These rules could significantly impact the costs of modifying existing thermal plants as well as building new thermal generation sources. We cannot determine or estimate the costs of compliance with such measures at this time.

In September 2009, the EPA finalized the Mandatory Reporting Rule (MRR) that requires facilities emitting over 25,000 metric tons of GHG a year to report their emissions to the EPA beginning in January 2011 for 2010 emissions On March 18, 2011, the EPA issued a rule extending the deadline for reporting 2010 GHG emissions data to September 30, 2011. Based on rule applicability criteria, Colstrip, Coyote Springs 2, and the Rathdrum CT recently reported GHGs to the EPA. The rule also required that natural gas distribution system throughput be reported along with the development of a GHG Monitoring Plan. On March 22, 2010, the EPA proposed to further amend its reporting rule to include several new source categories, including reporting of GHG fugitive emissions from electric power transmission and distribution systems, fugitive emissions from natural gas distribution systems, and fugitive emissions from natural gas storage facilities. Reporting for these additional sources for 2011 emissions is required by March 31, 2012.

State Activities

The states of Washington and Oregon have statutory targets to reduce GHG emissions. Washington s targets are intended to reduce GHG emission to 1990 levels by 2020; to 25 percent below 1990 levels by 2035; and to 50 percent below 1990 levels by 2050. Oregon s targets would reduce GHG emissions to 10 percent below 1990 levels by 2020 and 75 percent below 1990 levels by 2050. Both states enacted their targets expecting that they would be met through a combination of renewable energy standards, and assorted complementary policies, such as land-use policies, energy efficiency codes for buildings, renewable fuel standards and vehicle emission standards. However, neither state has adopted any comprehensive requirements aimed at achieving these targets.

In 2009, the Governor of Washington issued an Executive Order (09-05) directing the Washington Department of Ecology to estimate GHG emissions by sector and source and to identify potential reduction requirements for them in preparation for the eventual imposition of state and/or federal GHG regulations. The Department of Ecology has identified facilities that emit more than 25,000 metric tons of GHG annually and has forecasted that those facilities will need to reduce their emissions by 9.2 percent in order for the state to achieve its GHG emissions reduction target for 2020. Our natural gas distribution system has been specifically identified as a facility along with our thermal plants and contracts with thermal plants. Fossil-fueled generation outside of the state has also been generically identified as a facility for the purposes of potentially regulating GHG emissions associated with the importation of power to serve our Washington loads. The state of Washington has yet to identify how it might impose or enforce GHG emission reductions. Nevertheless, the State will make significant progress in meeting its GHG emission targets in light of the enactment of SB 5769, which codifies an agreement that the only coal-fired generation facility operating in the state (with which we have no involvement) to completely cease coal-fired operations by 2025.

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Washington State s Department of Ecology has adopted regulations to ensure that its State Implementation Plan comports with the requirements of the EPA s regulation of GHG emissions. We will continue to monitor actions by the department as it may proceed to adopt additional regulations under its CAA authorities. Late in 2011, a Federal District Court ruled that the Department of Ecology must require six refineries located in the State to install reasonably available control technology to control and reduce their greenhouse gas emissions. This decision turned, in part, on the meaning of air contaminate under Washington law. The court observed that while the operative statute did not explicitly identify greenhouse gases, Governor Gregoire s Executive Order (09-05) defined air contaminate as including greenhouse gases. It remains to be determined whether the decision will be appealed or if and how it might impact other industries.

Washington and Oregon apply a GHG emissions performance standard to electric generation facilities used to serve loads in their jurisdictions. The emissions performance standard prevents utilities from constructing or purchasing generation facilities, or entering into long-term contracts (five years or more) to purchase energy produced by plants that have emission levels higher than 1,100 pounds of GHG per MWh until 2012, at which time it will be reviewed and may be lowered by administrative rule to reflect the emissions profile of the latest commercially available combined-cycle combustion turbine.

Initiative Measure 937 (I-937), the Energy Independence Act, was passed into law through the 2006 General Election in Washington. I-937 requires investor-owned, cooperative, and government-owned electric utilities with over 25,000 customers to acquire qualified renewable energy resources and/or renewable energy credits in incremental amounts until those resources or credits equal 15 percent of the utility s total retail load in 2020. I-937 also requires these utilities to meet biennial energy conservation targets, the first of which must be met in 2012. Furthermore, by January 1, 2012, electric utilities subject to I-937 s mandates must have acquired enough qualified incremental renewable energy and/or renewable energy credits to meet 3 percent of their load. Failure to comply with renewable energy and energy efficiency standards could result in penalties of $50 per MWh or greater being assessed against a utility for each MWh it is deficient in meeting a standard. A utility would be deemed to comply with the renewable energy standard if it invests at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable energy resources and/or renewable energy credits. As noted in the following section, we have taken the steps necessary to meet the requirements of I-937.

Electric Integrated Resource Plan

In August 2011, we filed our 2011 Electric Integrated Resource Plan (IRP) with the WUTC and the IPUC. We are required to file an IRP every two years. The IRP details projected load growth 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 2011 IRP include:

- A contract for the 105 MW Palouse Wind, LLC project, which is expected to help meet the requirements of Washington state Energy Independence Act (I-937) beginning in 2016, as well as provide a new resource to serve our customers increasing energy needs.

- An additional 42 aMW of wind or qualifying renewable resource or energy credits are required under the same Act beginning in 2021.

- Energy efficiency measures are expected to save 310 aMW of cumulative energy over the 20-year IRP timeframe. This aggressive effort could reduce load growth to half of what it would be without these measures.

- 750 MW of new natural gas-fired generation facilities are required between 2018 and 2031.

Three grid modernization programs are projected to save 5 aMW of energy by 2013.

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.

In June 2011, we entered into a 30-year power purchase agreement (PPA) with Palouse Wind, LLC (Palouse Wind), an affiliate of First Wind Holdings, LLC. Under the PPA, we will acquire all of the power and renewable attributes produced by a wind project being developed by Palouse Wind in Whitman County, Washington. The wind project is expected to have a nameplate capacity of approximately 105 MW and produce approximately 40 aMW with deliveries beginning by the end of 2012. We decided to enter into this PPA due, in part, to market changes reducing the cost of renewable resource projects. This was due, in part, to tax incentives for the construction of renewable resource projects that remain in effect through 2012. We acquired the development rights for a separate wind generation site near Reardan, Washington in 2008 and continue to study that site in preparation for later development. We plan to meet the state of Washington s renewable energy standards until 2016 with a combination of qualified upgrades at our existing hydroelectric generation plants. The power purchased from Palouse Wind will help to meet our Washington renewable energy requirements beginning in 2016, as well as provide a new energy resource to serve our system retail load requirements. Under the PPA, we have the option to purchase the wind project each year following the 10th anniversary of the commercial operation date at a price determined under the contract.

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The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes or if new or modified renewable energy standards are enacted at either the state or federal levels.

As part of our IRP, we included estimates of climate change into the retail load forecast. The recent trend has been a warming climate compared to the 30-year normal. Trends in heating and cooling degree days for Spokane are roughly equal to the scientific community s predictions for this geographic area, implying one degree Fahrenheit of warming every 25 years. We do not expect this trend to have a material impact on our results of operations. Estimated costs of GHG emissions were also included in the development of the IRP market prices.

Clean Air Act

We must comply with the requirements under the Clean Air Act (CAA) in operating our thermal generating plants. The CAA currently requires a Title V operating permit for Colstrip (which is in the process of being renewed), Coyote Springs 2 (which will expire in 2013), the Kettle Falls GS (which will be renewed in 2012), and the Rathdrum CT (which will expire in 2016). Boulder Park and the Northeast CT currently require only minor source operating permits based on their limited operation and emissions. The CAA also requires Acid Rain Program monitoring, reporting and emissions trading for Colstrip, Coyote Springs 2 and the Rathdrum CT. We continue to monitor legislative and regulatory developments for several programs within the CAA such as the National Ambient Air Quality Standards (NAAQS), New Source Performance Standards and the National Emission Standards for Hazardous Air Pollutants (NESHAPs) or Maximum Achievable Control Technology (MACT).

Montana mercury regulation and the EPA s Mercury Air Toxic Standards (MATS)

In 2006, the Montana Department of Environmental Quality (Montana DEQ) adopted final rules for the control of mercury emissions from coal-fired plants that impose strict emission limitations beginning in 2010. Colstrip installed and is successfully operating a mercury emission control system which meets the Montana mercury regulation.

The EPA finalized the MATS (formerly known as the Utility MACT) on December 16, 2011 to control hazardous air pollutants including mercury from coal and oil-fired power plants. The final version of the rule contains a mercury standard that is less stringent than the Montana mercury regulation therefore Colstrip s existing emission control system should be sufficient to meet mercury compliance. For the remaining portion of the rule that specifically addresses Air Toxics (including metals and acid gases), the joint owners are currently evaluating what type of new emission controls systems may be needed for MATS compliance in 2015. We are unable to determine to what extent or if there will be any material impacts to Colstrip at this time.

National Ambient Air Quality Standards (NAAQS)

We continue to monitor legislative and regulatory developments at both the state and national levels for potential operating limitations that may results from updates to the NAAQS. The CAA requires regular updates which have been recently court mandated to occur in June 2013 for nitrogen dioxide, ozone and particulate matter. We have thermal power plants in Washington, Idaho, Montana and Oregon. Since the EPA has designated most of the western states in which we operate as attainment areas, we do not anticipate any material impacts on our thermal plants from the required updates of these new standards at this time.

Regional Haze Program

The United States Congress addressed regional visibility in the 1990 CAA amendments and the EPA published the final Regional Haze regulations in 2005. The EPA s regulations set a national goal of eliminating man-made visibility degradation in Class I areas by the year 2064. The States were expected to take actions through State Implementation Plans (SIPs) to make reasonable progress through 10-year plans, including application of Best Available Retrofit Technology (BART) requirements. In 2009, the EPA announced that many states had failed to submit the required SIPs by the 2007 deadline. In 2011, environmental groups sued the EPA for inaction which resulted in court ordered deadlines for a Montana Federal Implementation Plan (FIP) in July 2012.

BART is a retrofit program applied to large emission sources, including electric generating units built between 1962 and 1977. In February 2007, Colstrip was notified by the EPA that Colstrip Units 1 & 2 (of which we are not an owner) were determined to be subject to the EPA s BART requirements. In November 2010, the EPA issued a request for additional reasonable progress information for Colstrip Units 3 & 4 (of which we are a 15 percent owner). The owners of Colstrip Units 3 & 4 have submitted the requested information and await the EPA s upcoming FIP proposal, which will include the EPA s determination of BART for Colstrip Units 3 & 4. We are unable to determine to what extent or if there will be any material impacts to Colstrip at this time.

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Coal Ash Management/Disposal

Currently, coal combustion byproducts (CCBs) are not regulated by the EPA as a hazardous waste. Under a proposed rule issued in 2010, the EPA is reconsidering the classification of CCBs under the Resource Conservation and Recovery Act (RCRA). The draft rules included two options: to require management of CCBs as a hazardous waste under Subtitle C of the RCRA; or to regulate coal ash under Subtitle D, for non-hazardous solid wastes, with possible special waste requirements. Should the EPA determine to regulate CCBs as a hazardous waste under the RCRA, such action could have a significant impact on future operations of Colstrip.

Fisheries

A number of species of fish in the Northwest, including the Snake River sockeye salmon and fall chinook salmon, the Kootenai River white sturgeon, the upper Columbia River steelhead, the upper Columbia River spring chinook salmon and the bull trout, are listed as threatened or endangered under the Federal Endangered Species Act. Efforts to protect these and other species have not directly impacted generation levels at any of our hydroelectric facilities. We purchase power under long-term contracts with certain PUDs with hydroelectric generation projects on the Columbia River that are directly impacted by ongoing mitigation measures for salmon and steelhead. The reduction in generation at these projects is relatively minor, resulting in minimal economic impact on our operations at this time. We cannot predict the economic costs to us resulting from future mitigation measures. We received a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids in March 2001 that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, including bull trout, is a key part of the agreement. The result is a collaborative native salmonid restoration program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. The U.S. Fish & Wildlife Service issued an updated Critical Habitat Designation for bull trout in 2010 that includes the lower Clark Fork River, as well as portions of the Coeur d Alene basin within our Spokane River Project area, and is currently developing a final Bull Trout Recovery Plan under the ESA. Issues related to these activities are expected to be worked out through the ongoing collaborative effort of our Clark Fork and Spokane River FERC licenses. See Hydroelectric Licensing and Fish Passage at Cabinet Gorge and Noxon Rapids in Note 21 of the Notes to Consolidated Financial Statements for further information.

Western Power Market Issues

The FERC continues to conduct proceedings and investigations related to market controls within the western United States that include proposals by certain parties to impose refunds, and some of the FERC s decisions have been appealed in Federal Courts. Certain parties have asserted claims for significant refunds from us, which could result in liabilities for refunding revenues recognized in prior periods. We have joined other parties in opposing these proposals. We believe that we have adequate reserves established for refunds that may be ordered. The refund proceedings provide that any refunds would be offset against unpaid energy debts due to the same party. As of December 31, 2011, our accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties. See California Refund Proceeding and Pacific Northwest Refund Proceeding in Note 21 of the Notes to Consolidated Financial Statements for further information on the refund proceedings.

Other

For other environmental issues and other contingencies see Note 21 of the Notes to Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Our primary market risk exposures are:

- Commodity prices for electric power and natural gas

Credit related to the wholesale energy market

Interest rates on long-term and short-term debt

Foreign exchange rates between the U.S. dollar and the Canadian dollar

Commodity Price Risk

Electric Power Commodities

We are exposed to market risks for electric power because of:

imbalances between available power supply resources and our load obligations,

substitution of resources to achieve economic dispatch from available power supply choices, and

our objective to optimize the value of specific power resource facilities.

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Imbalances between available power supply resources and our electric load obligations arise because of seasonal factors, operating parameters of our facilities, contract rights and contract obligations, and variations in customer demand. We forecast both obligations and resources to estimate our future surplus or deficit positions. We hedge a portion of the open position with forward transactions that establish physical supply (or disposition) and/or financially-equivalent derivatives that mitigate economic uncertainty. Seasonal factors and prevailing weather affect power supplies. Supply is affected by both temperature and the timing and amount of precipitation, particularly with respect to our hydroelectric generation facilities that rely on river flows from immediate precipitation and from melting snow. Wind conditions affect the amount and timing of supply from wind generation facilities. Operational parameters affecting power resources include natural river flow, water storage and regulation-driven constraints for hydroelectric generation. Operational parameters also include maintenance requirements and forced outages at electric generating plants, fuel availability for thermal plants, environmental and other regulatory constraints and other factors.

Electric power obligations include retail customer demand and other commitments between Avista Corp. and other parties in the wholesale power market. Retail customer demand is sensitive to temperature extremes and to normal seasonal temperature variation that impacts customers heating and cooling-related demand for energy. Obligations are also affected by customer growth, economic conditions, technology that adds to or reduces electric demand, and choices that customers make about energy usage. Our forecasts of obligations consider contract terms, past energy demand patterns and indicators of potential changes in energy consumption.

Economic dispatch involves the decisions that we make in the mix of power resources to meet our retail customer requirements and other obligations. We make dispatch decisions to operate or not operate our resources and to dispose of energy or to obtain resources from others in the wholesale power market (including natural gas fuel markets). Hydroelectric generation is typically the lowest cost source of supply. Thermal generation resource costs vary with fuel costs and other factors. Power purchase agreements may provide us with variable power supply quantities and contract terms can include both fixed and variable costs.

To balance electric power resources and electric demand obligations, we enter into transactions in the wholesale power and fuel markets. These transactions include physical power and natural gas and derivative instruments based on wholesale prices of power and natural gas. Wholesale market prices tend to vary with natural gas fuel costs to the extent that natural gas-fired resources are the least cost alternative in the region (which is often the case in recent years). Wholesale prices also tend to vary with the extent of hydroelectric surplus or shortages, particularly during the highest hydroelectric generation periods of spring rains and snow melt. Wholesale prices also vary to a greater extent each year based on wind patterns as wind generation facilities have grown significantly in the region. Generating resource availability and regional demand tend to impact energy prices. Wholesale prices are quoted for energy to be delivered in time frames ranging from immediate real-time, to 30 minute, hourly, daily, multi-day, monthly, quarterly and annually. Future market prices extend several years into the future, though market liquidity tends to become limited beyond a few years into the future.

Natural Gas Commodities

Natural gas is a significant source of fuel for electric generation. We buy natural gas as fuel for electric generating facilities that we own and for the Lancaster Plant where we have contractual rights to dispatch its operation. We also sell natural gas when we have an opportunity to displace thermal generation with other power supply resources or when expected thermal generation does not actually occur for any reason.

We hedge a portion of these natural gas purchases and sales, including the use of physical delivery contracts and derivative instruments based on wholesale prices of natural gas. We also transact based on index pricing in the wholesale natural gas market and at spot market prices that can vary significantly.

Some, but not all, natural gas transactions related to thermal generation are executed concurrently with similar quantities of electric energy (based on physical fuel-to-power conversion parameters of generation facilities that we own or control). In such cases, the net economic cost or benefit between natural gas purchases and power sales (or gas sales offset by power purchases) will vary as each commodity price moves independently of the other.

We also purchase natural gas for delivery to retail natural gas customers. Some natural gas is purchased for injection into storage, which can later be withdrawn from storage. To a lesser extent, we also sell natural gas originally purchased for retail natural gas supply or inventory back into the wholesale market. Some of the wholesale natural gas transactions are executed at fixed prices for future delivery, while some are executed based on market index prices or spot prices. We transact for physical delivery of natural gas and we enter into swaps that create a financial hedge for future natural gas prices.

We also enter into natural gas transactions intended to extract value from our assets and contract rights. These asset optimization transactions include purchases and offsetting sales at two delivery locations when we have excess capacity available in natural gas pipelines (such pipelines are usually owned by other parties where we have contract rights for that capacity). Asset optimization strategies also include time difference purchases and sales of natural gas that use excess storage capacity available in our underground natural gas storage facilities. These transactions include commitments for future physical delivery and/or financial swaps tied to the price of natural gas.

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Matters Affecting Both Electric and Natural Gas Commodities

Variation in electric and natural gas commodity prices affects our cash flow, customer retail rates and the amount of net income we recognize. Regulatory cost recovery mechanisms address these power supply cost variations, such that a portion of the cost variation is passed on to customers and a portion is recognized by the Company. The timing of incurring costs can be significantly different than the timing for recovering costs, resulting in the need for a significant liquidity cushion. Historically, we have carried significant balances of deferred power supply and natural gas supply costs, which represent costs we expect to recover from customers in future retail rates, subject to approval by regulators.

When we have surplus electric generation, its value varies with market prices and economics of other resources in the region. When we have a shortage of electric generation from our own resources and other resources that we have long-term rights to control, the cost to obtain electric power or fuel varies. We make forecasts to estimate surplus and deficit conditions and we may enter into forward hedging arrangements to reduce the expected net surplus or deficit. Our forecasts cannot avoid uncertainty about loads or obligations and we do not attempt to fully hedge all forecast net open positions. Our hedges include forward transactions ranging from 30 minutes to multiple years in the future, with transaction blocks of 30 minute, hourly, daily, monthly, quarterly and annually. We are not able to predict how the combination of energy resources, energy loads, prices, rate recovery and other factors will ultimately drive deferred power costs and the timing of recovery of our costs in future periods. See further information at Avista Utilities - Regulatory Matters.

See Risk Management for additional information on our activities to hedge our exposure to price risk by making forward commitments for energy purchases and sales.

Wholesale electricity prices are affected by a number of factors, including:

- demand for electricity,
- the number of market participants and the willingness of market participants to trade,
- adequacy of generating reserve margins,
- scheduled and unscheduled outages of generating facilities,
- availability of streamflows for hydroelectric generation,
- price and availability of fuel for thermal generating plants, and
- disruptions to or constraints on transmission facilities.

Wholesale natural gas prices are affected by a number of factors, including:

- overall actual and expected changes in the North American natural gas supply mix including the growth in unconventional supplies such as natural gas from shale,
- natural gas production that can be delivered to our service areas,
- level of imports and exports, particularly from Canada by pipeline,
- level of inventories and regional accessibility,
- demand for natural gas, including natural gas as fuel for electric generation,
- the number of market participants and the willingness of market participants to trade,
- global energy markets, including oil or other natural gas substitutes, and
- availability of pipeline capacity to transport natural gas from region to region.

Any combination of these factors that results in a shortage of energy generally causes the market price to move upward. Factors such as a general economic downturn, increased proven energy reserves, or increased production generally reduce market prices for energy. In addition to these factors, wholesale power markets are subject to regulatory constraints including price controls.

Price risk also includes the risk of fluctuation in the market price of associated derivative commodity instruments (such as options and forward contracts). Price risk may also be influenced to the extent that the performance or non-performance by market participants of their contractual obligations and commitments affect the supply of, or demand for, the commodity.

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

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The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2011 that are expected to settle in each respective year (dollars in thousands):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical	Financial	Physical	Financial	Physical	Financial	Physical	Financial
2012	$ (11,063)	$ (25,363)	$ (36,597)	$ (9,505)	$ 1,007	$ 7,206	$ 985	$ 3,647
2013	(2,479)	(12,021)	(15,112)	(12,989)	(38)	10,060	(1,073)	7,360
2014	(1,203)	(72)	(4,500)	(3,014)	(88)	1,347	(918)	(235)
2015	(1,186)		(1,014)	(435)	(114)			
2016	(899)		(81)	46	(177)			
Thereafter	(695)				(817)			

Credit Risk

Credit risk relates to potential losses that we would incur as a result of non-performance of contractual obligations by counterparties to deliver energy or make financial settlements. We often extend credit to counterparties and customers, and we are exposed to the risk of not being able to collect amounts owed to us. Credit risk includes potential counterparty default due to circumstances:

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

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

We seek to mitigate credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring current credit exposures, and

conducting some of our transactions on exchanges with fully collateralized clearing arrangements that significantly reduce counterparty default risk.

Our credit policies include an evaluation of the financial condition and credit ratings of counterparties, collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. We also use standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty or affiliated group. However, despite mitigation efforts, the risk of default cannot be entirely eliminated.

We regularly evaluate counterparties credit exposure for future settlements and delivery obligations. We reduce or eliminate open (unsecured) credit limits and implement other credit risk reduction measures for parties perceived to have increased default risk. Counterparty collateral is used to offset our credit risk where warranted in light of unsettled net positions and their future obligations to us.

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

electric and natural gas utilities,

electric generators and transmission providers,

natural gas producers and pipelines,

financial institutions including commodity clearing exchanges and related parties, and

energy marketing and trading companies.

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

Credit risk also involves demands on our capital. We are subject to limits and credit risks that counterparties perceive related to our ability to perform deliveries and settlement under physical and financial energy contracts. Many of our counterparties allow unsecured credit at limits prescribed by agreements or their discretion. Capital requirements for certain transaction types involve a combination of initial margin and market value margins without any unsecured credit threshold. Counterparties may seek assurances of performance from us in the form of letters of credit, prepayment or cash deposits.

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

Counterparties credit exposure to us is dynamic in normal markets and may change significantly in more volatile markets. The amount of potential default risk to us from each counterparty depends on the extent of forward contracts, unsettled transactions and market prices. There is a risk that we may seek additional collateral from counterparties that are unable or unwilling to provide it.

Risk Management for Energy Resources

We use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have an energy resources risk policy and control procedures to manage these risks, both qualitative and quantitative. Our Risk Management Committee has established our risk management policy for energy resources. The Risk Management Committee is comprised of certain officers and other management. The Audit Committee of the Company s Board of Directors periodically reviews and discusses enterprise risk management processes, and it focuses on the Company s material financial and accounting risk exposures and the steps management has undertaken to control them. Our Risk Management Committee reviews the status of risk exposures through regular reports and meetings. Nonetheless, adverse changes in commodity prices, generating capacity, customer loads, regulation and other factors may result in losses of earnings, cash flows and/or fair values.

Our Risk Management Committee has also established a wholesale energy markets credit policy. The credit policy is designed to reduce the risk of financial loss in case counterparties default on delivery or settlement obligations and to conserve our liquidity as other parties may place credit limits or require cash collateral.

In implementing our risk management policy for energy resources, we measure the volume of monthly, quarterly and annual energy imbalances between projected power loads and resources. The measurement process is based on expected loads at fixed prices (including those subject to retail rates) and expected resources to the extent that costs are essentially fixed by virtue of known fuel supply costs or projected hydroelectric conditions. To the extent that expected costs are not fixed, either because of volume mismatches between loads and resources or because fuel cost is not locked in through fixed price contracts or derivative instruments, our risk policy guides the process to manage this open forward position over a period of time. Normal operations result in seasonal mismatches between power loads and available resources. We are able to vary the operation of generating resources to match parts of 30 minute, hourly, daily and weekly load fluctuations. We use the wholesale power markets, including the natural gas market as it relates to power generation fuel, to sell projected resource surpluses and obtain resources when deficits are projected. We buy and sell fuel for thermal generation facilities based on comparative power market prices and marginal costs of fueling and operating available generating facilities and the relative economics of substitute market purchases for generating plant operation.

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

Electric load/resource imbalances within a planning horizon up to 41 months ahead are compared against established volumetric guidelines. Management determines the timing and actions to manage the imbalances. We also assess available resource alternatives and actions that are appropriate for longer-term planning periods. Expected load and resource volumes for forward periods are based on monthly and quarterly averages that may vary significantly from the actual loads and resources within any individual month or operating day. Future projections of resources are updated as forecasted streamflows and other factors differ from prior estimates. Forward power markets may be illiquid, and market products available may not match our desired transaction size and shape. Therefore, open imbalance positions exist at any given time.

Our projected natural gas loads and resources are regularly reviewed by operating management and the Risk Management Committee. To manage the impacts of volatile natural gas prices, we seek to procure natural gas through a diversified mix of spot market purchases and forward fixed price purchases from various supply basins and time periods. We have an active hedging program that extends four years into the future with the goal of reducing price volatility in our natural gas supply costs. We use natural gas storage capacity to support high demand periods and to procure natural gas when prices are likely to be seasonally lower. Securing prices throughout the year and even into subsequent years at multiple basins mitigates potential adverse impacts of significant purchase requirements in a volatile price environment.

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Interest Rate Risk

We are affected by fluctuating interest rates related to a portion of our existing debt and our future borrowing requirements. We manage interest rate exposure by limiting our variable rate exposures to a percentage of total capitalization. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and through the use of fixed rate long-term debt with varying maturities. We also hedge a portion of our interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements.

These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

As of December 31, 2011, we had outstanding interest rate swap agreements with a total notional amount of $75.0 million and a mandatory cash settlement date of July 2012. We also have interest rate swap agreements with a notional amount of $85.0 million and a mandatory cash settlement date of June 2013.

As of December 31, 2011, we had a derivative liability of $18.9 million and an offsetting regulatory asset on the Consolidated Balance Sheets in accordance with regulatory accounting practices. Upon settlement of the interest rate swaps, the regulatory asset or liability (included as part of long-term debt) will be amortized as a component of interest expense over the life of the forecasted interest payments.

We estimate that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2011 would decrease this derivative liability by $3.4 million, while a 10-basis-point decrease would increase the liability by $3.4 million.

The interest rate on $51.5 million of long-term debt to affiliated trusts is adjusted quarterly, reflecting current market rates. Amounts borrowed under our committed line of credit agreements have variable interest rates.

The following table shows our long-term debt (including current portion) and related weighted average interest rates, by expected maturity dates as of December 31, 2011 (dollars in thousands):

	2012	2013	2014	2015	2016	Thereafter	Total	Fair Value
Fixed rate long-term debt	$ 7,000	$ 50,000				$ 1,127,100	$ 1,184,100	$ 1,369,763
Weighted average interest rate	7.37%	1.68%				5.57%	5.42%	
Fixed rate nonrecourse long-term debt of Spokane Energy	$ 13,668	$ 14,965	$ 16,407	$ 1,431			$ 46,471	$ 51,974
Weighted average interest rate	8.45%	8.45%	8.45%					