AVISTA Corp.

# INVESTING IN OUR **SHARED** FUTURE

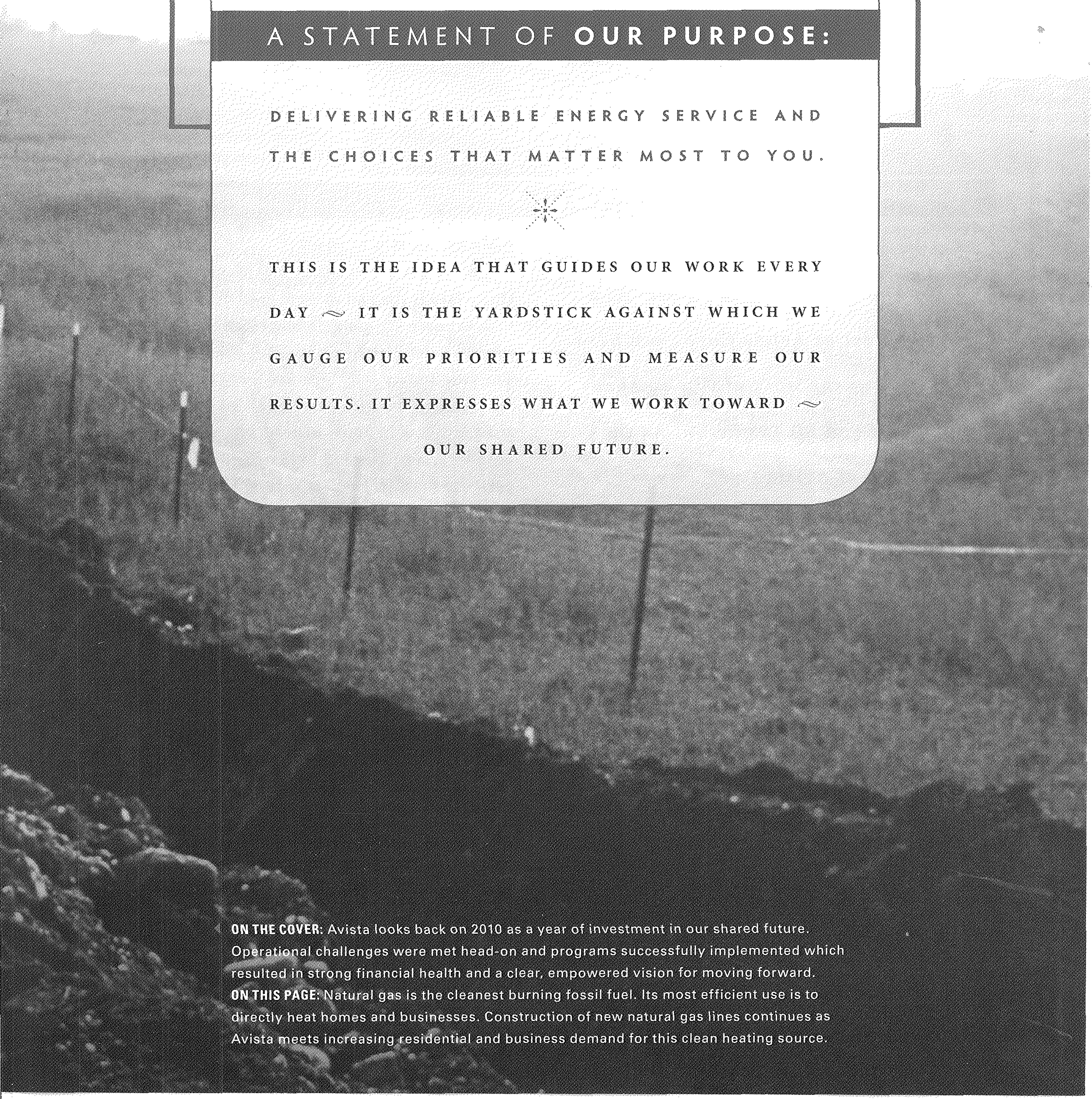
2010 ANNUAL REPORT

AVISTA
Corp.

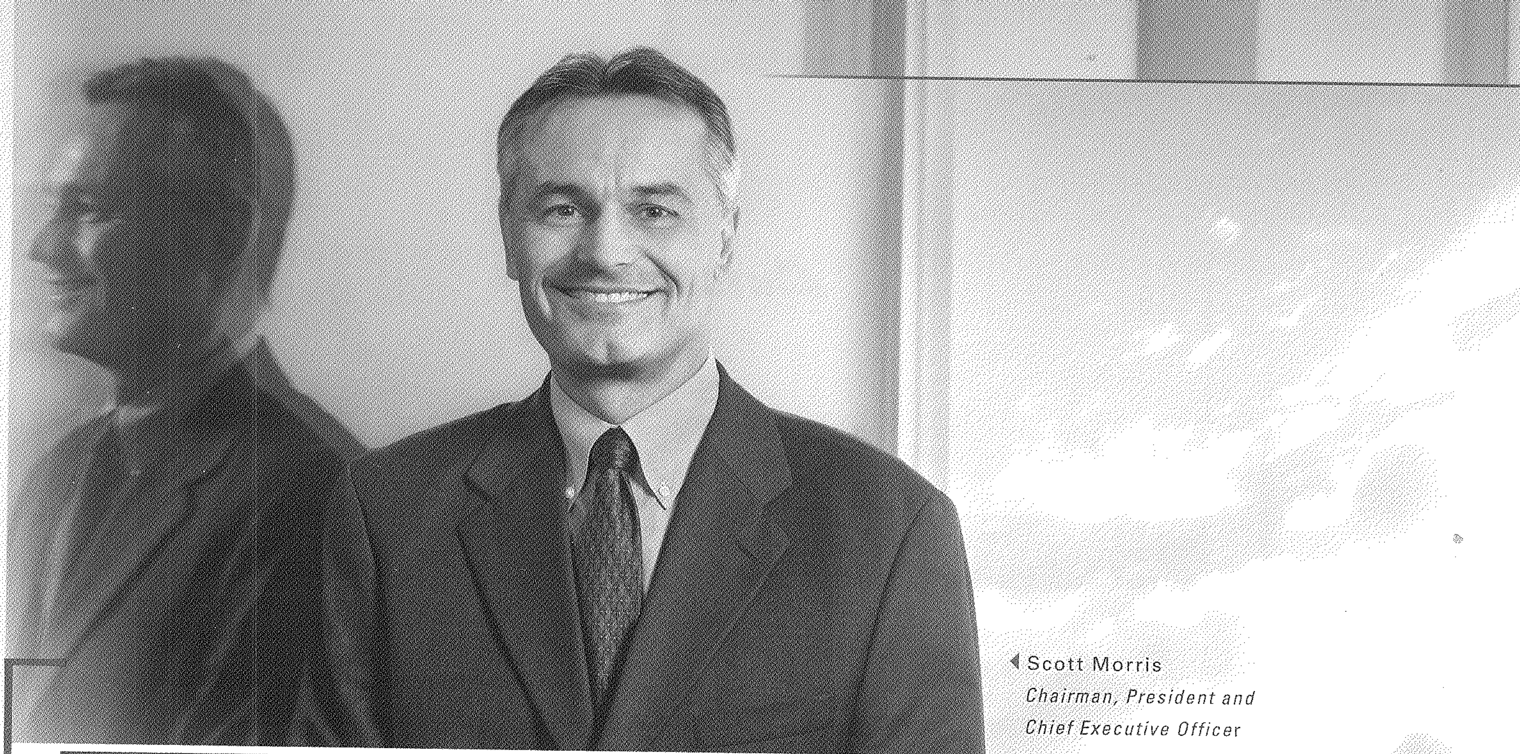
# A STATEMENT OF **OUR PURPOSE:**

DELIVERING RELIABLE ENERGY SERVICE AND THE CHOICES THAT MATTER MOST TO YOU.

THIS IS THE IDEA THAT GUIDES OUR WORK EVERY DAY ~ IT IS THE YARDSTICK AGAINST WHICH WE GAUGE OUR PRIORITIES AND MEASURE OUR RESULTS. IT EXPRESSES WHAT WE WORK TOWARD ~ OUR SHARED FUTURE.



**ON THE COVER:** Avista looks back on 2010 as a year of investment in our shared future. Operational challenges were met head-on and programs successfully implemented which resulted in strong financial health and a clear, empowered vision for moving forward.
**ON THIS PAGE:** Natural gas is the cleanest burning fossil fuel. Its most efficient use is to directly heat homes and businesses. Construction of new natural gas lines continues as Avista meets increasing residential and business demand for this clean heating source.



Scott Morris
*Chairman, President and Chief Executive Officer*

## DEAR FELLOW **SHAREHOLDERS:**

Let's talk about two thoughts: *shared value and shared future.* As a shareholder of Avista Corp., you have invested in the work of this company – for today and for tomorrow. As the chairman of Avista Corp., my job is to see that your trust in our work is paid back as a fair return on your investment. Together, we have a vested interest in the ongoing success of this company. So, please read on for a good sense of the work we're doing and the direction we're heading.

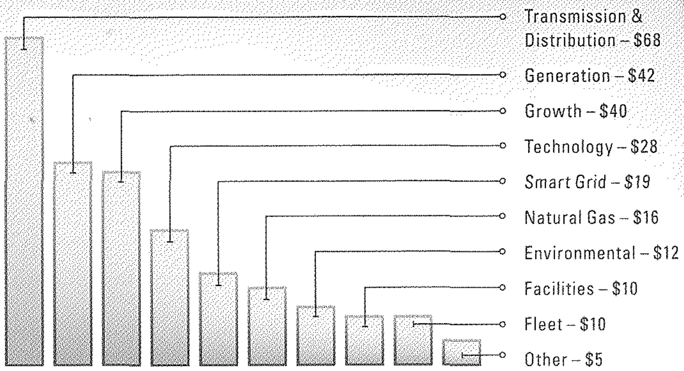
### FINANCIAL HIGHLIGHTS

We've come through 2010 with solid financial results and modest growth. We believe these are good outcomes given the weak economy both regionally and nationally. The year started with weather that once again set records. This time, though, it wasn't record snow levels as in 2009; instead 2010 was one of the warmest January to March time periods in this region. This resulted in lower than normal energy use from customers to heat their homes and businesses. However, improved results throughout the remainder of the year, power supply costs lower than the amount included in rates and our disciplined management of operating expenses helped to mostly offset the effects of the first quarter weather.

With that, we delivered year-end earnings of $1.65 per diluted share, an increase from $1.58 in 2009. Our 2011 earnings are expected to benefit from a return to normal weather and the effects of general electric and natural gas rate increases we received in Washington and Idaho. We expect this may be partially offset, however, by slower load growth due to the still-sluggish economy, a lag in the recovery of operating expenses and capital investments, as well as increased costs for materials.

## 2011 CAPITAL BUDGET

(total capital budget $250 million) ($ in millions)

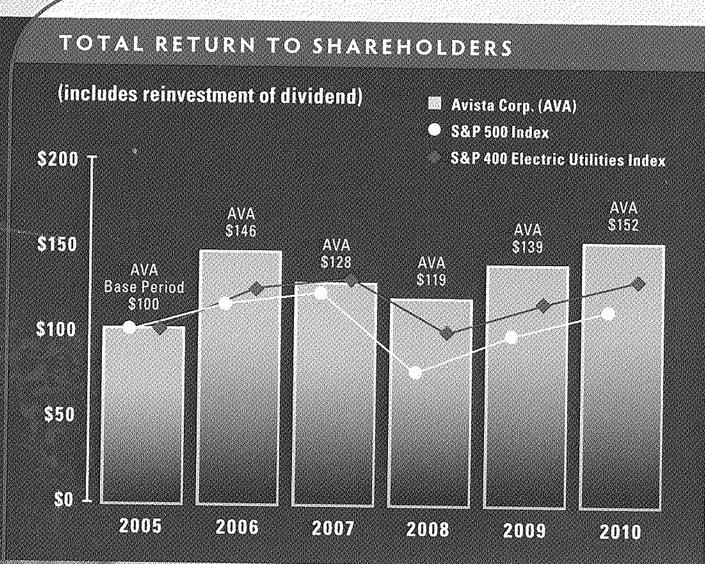


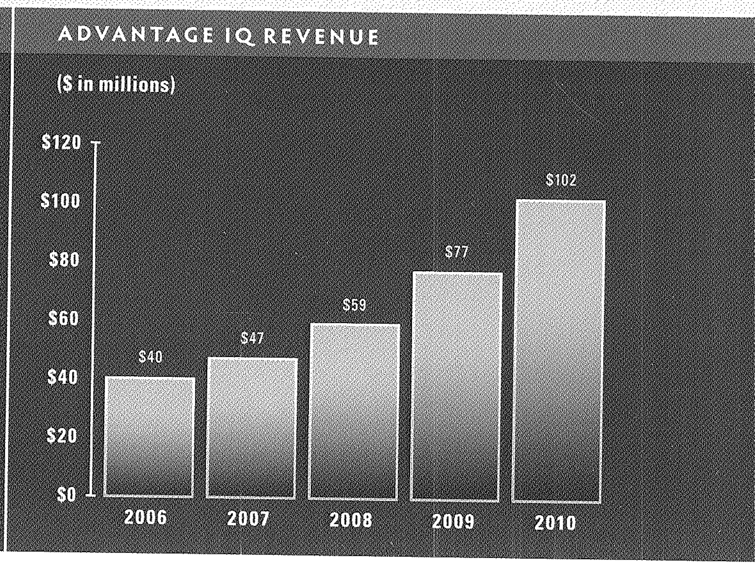

We remain committed to investing in our utility infrastructure to keep system reliability high. Replacing and upgrading our transmission and distribution system and renewable hydroelectric generation plants, as well as building the infrastructure to meet regional demand growth were the primary drivers of our $210 million capital budget in 2010. The 2011 capital budget of $250 million includes funds to match our smart grid grants.

As we invest in our system to reliably and safely bring energy to our customers, we are also diligently working with our regulators to receive timely recovery of these investments. In addition to the electric and natural gas rate increases in Washington and Idaho, we filed a natural gas rate case in Oregon in September. A proposed settlement has been reached subject to commission approval expected in the first half of 2011.

We remain focused on maintaining a healthy balance sheet and credit rating strength. At the end of 2010 we had a combined $258 million of available liquidity under our two committed lines of credit. We also have a sales agency agreement in place to sell shares of common stock from time to time. In 2010 we issued $43 million of common stock under this agreement, and we expect to issue up to $25 million of common stock in 2011 to maintain an appropriate capital structure.

Another sign of progress: the Board of Directors raised the common stock dividend in 2010 for the eighth consecutive year, bringing our dividend payout ratio to 60 percent and reaching our goal of being in line with the industry average. This reflects the confidence our directors have in our continued progress toward achieving our corporate goals.



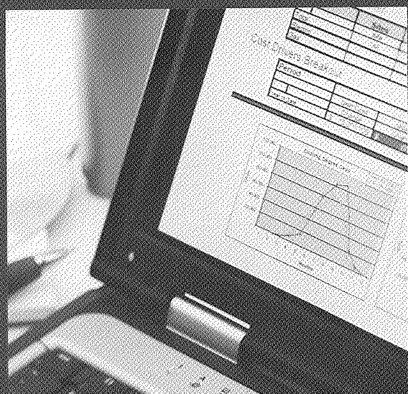




## STRATEGIC ENERGY MANAGEMENT

We are on the cusp of some of the biggest changes our industry has seen in decades – driven by new technology, new information and new partnerships. The opportunities and challenges ahead are very exciting. Being innovative in the way we look for opportunities is nothing new for us. It's deeply rooted in our history. Avista has long been an innovative energy company, from pioneering transmission and generation operations to helping create the automated meter reading industry; from developing fuel cell innovations to becoming the leader in energy management.

Advantage IQ, our primary non-utility subsidiary, is a leading provider of strategic energy management solutions. It partners with Fortune 1000 organizations to maximize business results by reducing energy and other facility expenses, managing risk and improving environmental performance. Its strategic acquisitions – including Ecos in 2009 and The Loyalton Group in 2010 – have broadened the value proposition Advantage IQ brings to its clients. Through the energy consumption information it manages for clients, Advantage IQ has an electric usage database of more than 25,000 megawatts of commercial and industrial load. This business

SMART ADVANTAGES — ADVANTAGE IQ



With energy in the top five expense categories for most businesses, visibility and understanding of how to best utilize energy is crucial. The value-added online tools, data resources and consulting we provide our clients make a competitive difference, helping them make informed decisions that can positively impact their financial stability and the environment. It is a win-win situation.

**Doug Barry**
*Manager, Advanced Analysis, Advantage IQ*

continues to show long-term growth potential in clients, revenues and its positive contribution to Avista Corp.'s earnings.

## SMART MOVES AT THE RIGHT TIME

Being in the right place, at the right time, with the right resources means we can capitalize on opportunities when they arise – enhancing our annual revenues and helping moderate power supply costs for customers. For example, Avista regularly sells available capacity, energy, ancillary services and green, renewable energy in the western markets. By optimizing the value of our resources through these activities, we are able to capture millions of dollars in additional revenue that serves to lower costs for our retail customers.

Doing due diligence is our first step in implementing new technologies. Such is the case with the advent of smart grid. There's a lot to know before we make full-scale investments in hardware and technology. As one of a handful of utilities to receive multiple smart grid grants under the American Recovery and Reinvestment Act of 2009, we're putting these funds to good use – enhancing our distribution system to improve reliability and energy efficiency; modeling how to implement new technology and communicate with customers in the Smart Grid Demonstration Project (Pullman, Wash.); and developing the workforce needed to install and maintain the new technologies. The smart grid capabilities we're building into our system today position us well as a trusted and knowledgeable partner with our customers in managing their energy use tomorrow.

New, enabling technologies, plus a fast-changing market and evolving customer needs demand that we engage with our customers in new ways. We're working from our strength, building on a solid foundation of customer satisfaction. Among other indicators, our customer service center has achieved over 90 percent satisfaction ratings from customers for more than 10 consecutive years. And in 2010, J.D. Power and Associates ranked Avista "Highest in Customer Satisfaction with Residential Natural Gas Service in the Western U.S. among Mid-size Utilities in a Tie."

We are focusing on identifying more ways to create value-added interactions with our customers. Our award-winning Web site is a dynamic resource for doing business with us and finding information to help manage energy use. We're among the industry leaders in using social media channels such as the Avista blog, Twitter and Facebook to communicate with our customers where the conversations are happening – in the digital world. We're holding community meetings with opportunities for customers, civic leaders and elected officials to share ideas and help us deliver responsive energy solutions. We're undertaking outreach activities

**Gerard Fischer**
*Avista Utilities*
*Residential Customer*

Our energy future relies on making the most efficient use of the resources that produce the power we need. Avista's in-home audit showed where I could cut energy losses and better manage utility costs, saving money, making my home more comfortable and helping me be a better steward of the environment.

Wattson, Avista's energy watchdog, attended more than 25 community events and school presentations in 2010, reaching more than 100,000 people and bringing the message of energy efficiency and conservation to the next generation of Avista customers. Avista engages people of all ages, empowering them to make informed energy choices.

**Savannah Miller**
*"Every Little Bit" video contestant*

My friends and I talk about how our planet belongs to everybody and how we should make sure there is something left for generations to come. Making a video for Avista's "Every Little Bit" contest got me thinking about how important it is for teenagers to save energy, like turning off lights and unplugging cell phone chargers.

such as our energy fairs that provide demonstrations, workshops and direct access to energy assistance for limited-income and senior customers. And we're talking with customers, one person at a time, answering questions and sharing more information about our business than ever before.

Internally, we're focused on strengthening the alignment of our actions to the company's strategic goals by enhancing planning and scheduling to boost the efficiency of our field workforce. We're developing processes to better prioritize projects so we spend money on what matters most when managing assets and technology. And we're implementing collaborative strategies to guide our purchasing decisions – what we buy, how we buy it and which suppliers we use. Through these and other initiatives, we are positioning the company to continue our success into the new energy future.

## STEWARDSHIP AS A WAY OF BUSINESS

We are committed to doing our part to keep the communities we serve healthy, vibrant places for families and businesses to thrive. Our long-standing partnerships throughout our service territory serve us all well.

Our environmental stewardship responsibilities are something else we take seriously. With two major hydroelectric facilities on the Clark Fork River in Montana and Idaho and six on the Spokane River from Idaho through eastern Washington, we invest millions of dollars each year in water quality, wetlands, fish and wildlife enhancements and other environmental benefits. In 2009 we received new federal licenses to operate our plants in the Spokane River Project. This success came from working closely with more than 200 stakeholders from governmental, tribal and community organizations.

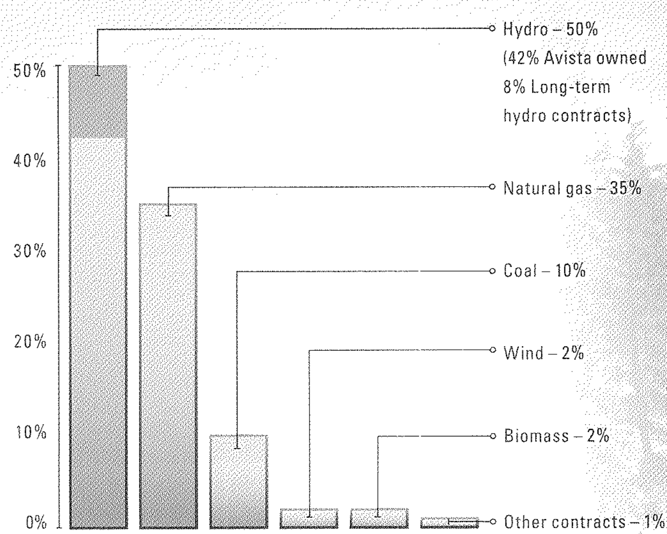
In the past year, we've embarked on the first stages of work to improve the aesthetic flows of the river through the jewel of downtown Spokane – Riverfront Park. And in partnership with others, we're working to protect and enhance water quality in the Spokane River and nearby aquifer.


Events like "Powering Our Future" brought the community together in 2010 to discuss energy challenges, choices, opportunities and costs. This event included interactive discussions with Avista energy experts, national energy leaders and community members sharing ideas about how all of us can help shape our energy future.

An important outcome of Avista's partnerships with tribes, community organizations, and state and federal agencies is the environmental protection of 1,200 acres of riparian habitat along the Clark Fork River in Idaho and Montana.

## ELECTRICITY GENERATION RESOURCE MIX

(as of December 31, 2010)



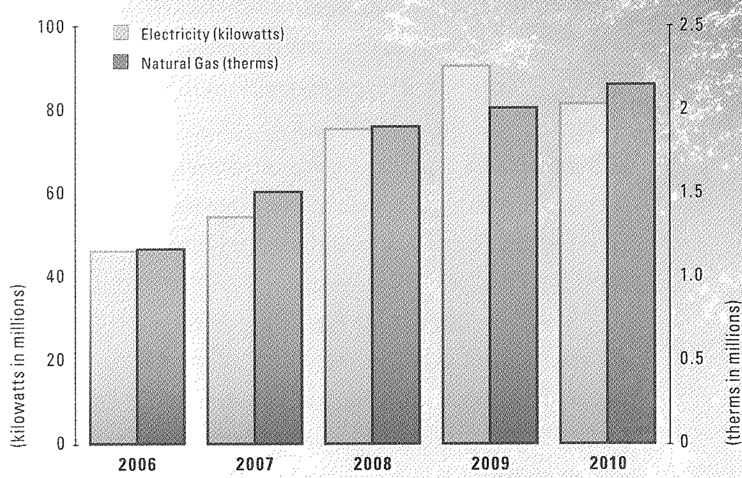

In a historic move last fall, we replaced wooden, manually-operated flashboards with computerized spill gates at the Nine Mile Hydroelectric Development, the first permanent spill gates in the dam's 102-year-history. Using innovative technology, the new gates allow us to maintain the upstream reservoir pool at a more consistent level throughout the year and generate more power using the same amount of water.

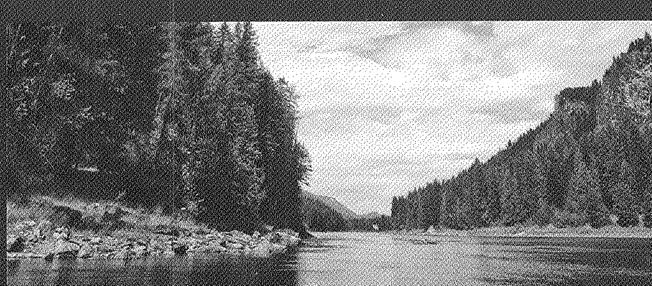
We are proud that Avista has always been one of the cleanest utilities in the country. Today, we are ranked 11th lowest in the rate of $CO_2$ emissions of the 100 largest electric power producers in the U.S., according to the 2010 report of the National Resources Defense Council. And with the delivery of electric vehicles to mainstream consumers, we're piloting a program with our own electric-hybrid cars and charging stations to help us plan for the ways in which this will affect our customers and the new demand for resources.

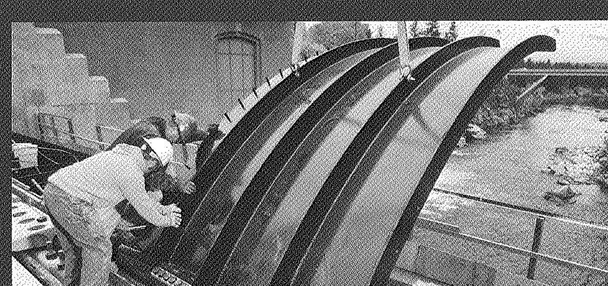
▼ Upgrading Avista's hydroelectric projects, like the Nine Mile Dam, enhances power generation capacity and efficiency. **BELOW:** Installation of computerized spill gates provides sensitive control of water flow, enhancing the environment and the aesthetics of the river.

## CUSTOMER ENERGY EFFICIENCY SAVINGS

(Washington and Idaho)






Avista employees turn ideas and plans into action, improving our infrastructure, maintaining our energy delivery systems and delivering reliable power to our customers when and where they need it.

**Mary B. Verner**
*Mayor, City of Spokane*

It's our responsibility to lead by example in shaping our city's energy future – a future that includes sustainable energy savings, supports the development of jobs and positions our city as a national leader in the responsible use of energy for the benefit of our citizens.

## A REFINED VISION TO NAVIGATE TO THE FUTURE

The economy in the Pacific Northwest remains challenged, with job markets slower than the national average to rebound from their recession lows. Employment levels throughout our service area remain well below trend after significant and persistent cutbacks in the construction and forest product sectors. The mining and manufacturing sectors are above their recession lows, but they remain well below pre-recession levels.

However, we remain positive in our outlook of achieving our goal of 5 percent to 7 percent long-term earnings growth for our company through a combination of growth in rate base, customer numbers and load productivity, as well as growth at Advantage IQ.

It will be important for us going forward that we are focused on alignment and adaptability – to align ourselves for the work that must be done today, with an eye to the changes in the industry that are ahead. We are poised to adapt to the changes in our industry and the markets as they come, while keeping our focus on the work of providing the reliable and safe energy services our customers want, expect and deserve.

The days of utilities existing just to keep the lights and heat on are waning. As the energy industry moves forward, we're seeing other businesses enter our marketplace, offering energy services. Our plans for the future are clear: grow our core reliable energy delivery business and continue to develop innovative energy services for our customers. By offering information, options for use and new technology, we'll increase the value our customers get from the energy they choose to use.

No doubt, what happens in the next few years will be shaped by the continued discussion, debate and decisions about renewable energy, carbon emissions and new mandates that will impact our operations and costs. We are active participants in that dialogue, and we will remain nimble in our planning to accommodate and to capitalize on new requirements.

Finally, and most importantly, I want to extend my deep appreciation to our employees. It is their dedication, talent and innovation that truly inspire me. They are the energy for this energy company. And to you, our shareholder, or perhaps potential shareholder, thank you for your belief in and support for our company. We will continue to do our very best to keep delivering *shared value for our shared future.*

Sincerely,

Scott Morris

Scott L. Morris
*Chairman, President and Chief Executive Officer*

# CORPORATE **LEADERSHIP**

## BOARD OF DIRECTORS

**Erik J. Anderson, 52**
President
Westriver Capital
Kirkland, Washington
Director since 2000

**Kristianne Blake, 57**
President
Kristianne Gates Blake, P.S.
Spokane, Washington
Director since 2000

**Roy L. Eiguren, 59**
President
Sullivan, Reberger & Eiguren
Boise, Idaho
Director since 2002

**John F. Kelly, 66**
President & CEO
John F. Kelly & Associates
Coral Gables, Florida
Director since 1997

**Rebecca A. Klein, 45**
Principal
Klein Energy, LLC
Austin, Texas
Director since 2010

**Scott L. Morris, 53**
Chairman of the Board,
President & CEO
Avista Corp.
Spokane, Washington
Director since 2007

**Michael L. Noël, 69**
President
Noël Consulting Company
Prescott, Arizona
Director since 2004

**Marc F. Racicot, 62**
Bigfork, Montana
Director since 2009

**Heidi B. Stanley, 54**
Co-owner & Chairman
Empire Bolt & Screw, Inc.
Spokane, Washington
Director since 2006

**R. John Taylor, 61**
Chairman & CEO
CropUSA Insurance Agency
Lewiston, Idaho
Director since 1985

## BOARD COMMITTEES

**Corporate Governance/ Nominating Committee**
Kristianne Blake
R. John Taylor
John F. Kelly – Chair

**Executive Committee**
Kristianne Blake
John F. Kelly
R. John Taylor
Scott L. Morris – Chair

**Audit Committee**
Roy L. Eiguren
Michael L. Noël (Financial Expert)
Heidi B. Stanley
Kristianne Blake – Chair

**Compensation & Organization Committee**
John F. Kelly
Rebecca A. Klein
Michael L. Noël
R. John Taylor – Chair

**Finance Committee**
Marc F. Racicot
Heidi B. Stanley
Erik J. Anderson – Chair

**Energy, Environmental & Operations Committee**
Erik J. Anderson
Rebecca A. Klein
Marc F. Racicot
Roy L. Eiguren – Chair

## CORPORATE & BUSINESS UNIT OFFICERS

**Scott L. Morris, 53**
Chairman of the Board,
President & CEO

**Mark T. Thies, 47**
Senior Vice President & CFO

**Marian M. Durkin, 57**
Senior Vice President,
General Counsel &
Chief Compliance Officer

**Karen S. Feltes, 55**
Senior Vice President &
Corporate Secretary

**Dennis P. Vermillion, 49**
Senior Vice President &
Environmental Compliance Officer
President, Avista Utilities

**Christy M. Burmeister-Smith, 54**
Vice President, Controller &
Principal Accounting Officer

**James M. Kensok, 52**
Vice President & CIO

**Don F. Kopczynski, 55**
Vice President

**David J. Meyer, 57**
Vice President &
Chief Counsel for Regulatory
& Governmental Affairs

**Kelly O. Norwood, 52**
Vice President

**Richard L. Storro, 60**
Vice President

**Jason R. Thackston, 40**
Vice President

**Roger D. Woodworth, 54**
Vice President

**Diane C. Thoren, 58**
Treasurer

**Jeffrey D. Heggedahl, 46**
President & CEO, Advantage IQ

# FINANCIAL AND OPERATING **HIGHLIGHTS**

| *(dollars in thousands except statistics and per share amounts or as otherwise indicated)* | 2010 | 2009 | 2008 |
|---|---|---|---|
| **FINANCIAL RESULTS** | | | |
| Operating revenues | $ 1,558,740 | $ 1,512,565 | $ 1,676,763 |
| Operating expenses | 1,328,552 | 1,311,907 | 1,491,852 |
| Income from operations | 230,188 | 200,658 | 184,911 |
| Net income | 94,948 | 88,648 | 74,757 |
| Net income attributable to Avista Corporation | 92,425 | 87,071 | 73,620 |
| Earnings per common share attributable to Avista Corporation, diluted | 1.65 | 1.58 | 1.36 |
| Earnings per common share attributable to Avista Corporation, basic | 1.66 | 1.59 | 1.37 |
| Dividends paid per common share | 1.00 | 0.81 | 0.69 |
| Book value per common share | $ 19.71 | $ 19.17 | $ 18.30 |
| Average common shares outstanding | 55,595 | 54,694 | 53,637 |
| Actual common shares outstanding | 57,120 | 54,837 | 54,488 |
| Return on average Avista Corporation stockholders' equity | 8.5% | 8.5% | 7.7% |
| Common stock closing price | $ 22.52 | $ 21.59 | $ 19.38 |
| **OPERATING RESULTS** | | | |
| **Avista Utilities** | | | |
| Retail electric revenues | $ 683,340 | $ 703,951 | $ 635,102 |
| Retail kWh sales (in millions) | 8,843 | 8,942 | 9,017 |
| Retail electric customers at year-end | 358,895 | 356,536 | 354,657 |
| Wholesale electric revenues | $ 165,553 | $ 88,414 | $ 141,744 |
| Wholesale kWh sales (in millions) | 3,803 | 2,354 | 1,964 |
| Sales of fuel | $ 106,375 | $ 32,992 | $ 44,695 |
| Other electric revenues | 19,015 | 15,426 | 16,916 |
| Retail natural gas revenues | 297,920 | 396,203 | 440,692 |
| Wholesale natural gas revenues | 197,364 | 143,524 | 281,668 |
| Transportation and other natural gas revenues | $ 15,965 | $ 14,691 | $ 11,847 |
| Total therms delivered (in thousands) | 923,096 | 888,301 | 845,710 |
| Retail natural gas customers at year-end | 318,996 | 316,201 | 314,102 |
| Net income attributable to Avista Corporation | $ 86,681 | $ 86,744 | $ 70,032 |
| **Advantage IQ** | | | |
| Revenues | $ 102,035 | $ 77,275 | $ 59,085 |
| Net income attributable to Avista Corporation | 7,433 | 5,329 | 6,090 |
| **Other** | | | |
| Revenues | $ 61,067 | $ 40,089 | $ 45,014 |
| Net loss attributable to Avista Corporation | (1,689) | (5,002) | (2,502) |
| **FINANCIAL CONDITION** | | | |
| Total assets | $ 3,940,095 | $ 3,606,959 | $ 3,630,747 |
| Long-term debt (including current portion) | 1,101,857 | 1,071,338 | 826,465 |
| Nonrecourse long-term debt of Spokane Energy (including current portion) | 58,934 | — | — |
| Long-term debt to affiliated trusts | 51,547 | 51,547 | 113,403 |
| Total Avista Corporation stockholders' equity | $ 1,125,784 | $ 1,051,287 | $ 996,883 |

Avista Corp.

# RELIABLE ENERGY – **EMPOWERING** CHOICES

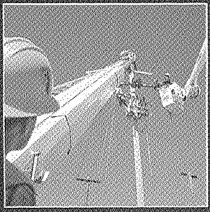
2010 FORM 10-K

AVISTA CORP (AVA)

# FORM 10-K

Filed: February 25, 2011 (Period: December 31, 2010)

Annual report which provides a comprehensive overview of the company for the past year.



Successful navigation through a myriad of energy technologies and options is vital to the delivery of reliable, cost-effective energy solutions. Avista is installing smart circuit communication technologies as part of our energy distribution system. This automated technology identifies the location of power outages and re-routes power from other sources reducing the frequency and duration of outages for our electric customers.

SEC Mail Processing Section

MAR 30 2011

Washington, DC
110

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

## FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED **DECEMBER 31, 2010** OR

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

**Commission file number 1-3701**

# AVISTA CORPORATION
(Exact name of Registrant as specified in its charter)

| | |
|---|---|
| Washington | 91-0462470 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| 1411 East Mission Avenue, Spokane, Washington | 99202-2600 |
| (Address of principal executive offices) | (Zip Code) |

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

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

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

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

Title of Class
Preferred Stock, Cumulative, Without Par Value

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

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

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

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

Indicate by check mark 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. ☐

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

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

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

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 $1,081,138,342 based on the last reported sale price thereof on the consolidated tape on June 30, 2010.

As of January 31, 2011, 57,276,041 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 12, 2011 | Part III, Items 10, 11, 12, 13 and 14 |

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** = not an applicable item in the 2010 calendar year for Avista Corporation*

*(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 |
| **Advantage IQ** | – Advantage IQ, Inc., provider of facility information and cost management services for multi-site customers throughout North America, subsidiary of Avista Capital |
| **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 Advantage IQ in 2009 |
| **Energy** | – The amount of electricity produced or consumed over a period of time, measured in KWH or MWH |
| **EPA** | – Environmental Protection Agency |
| **ERM** | – The Energy Recovery Mechanism in the state of Washington |
| **FASB** | – Financial Accounting Standards Board |

| Acronym/Term | Meaning |
|---|---|
| **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 |
| **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 |

## 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," "predicts," and similar expressions. Forward-looking statements (including those made in this Annual Report on Form 10-K) are subject to a variety of risks 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 and precipitation levels) 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 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;
- 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;
- economic conditions in our service areas, including the effect on the demand for, and customers' payment for, our utility services;
- the potential effects of legislation or administrative rulemaking, including the possible adoption of national or state laws requiring 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;
- 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 or vandalism that damage or disrupt information technology systems;
- delays or changes in construction costs, and 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; 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 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.

# 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, 2010, we employed 1,554 people in our utility operations and 945 people in our subsidiary businesses. Our corporate headquarters are in Spokane, Washington, the hub of the Inland Northwest. Historically, the primary industries in our service areas were mining, lumber and wood products, military and agriculture. Although they remain important, our economy is now more diversified. Health care, higher education, finance, manufacturing and tourism are also important sectors. Retail trade, governmental and professional services have expanded to serve a larger population.

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.
- **Advantage IQ** — an indirect subsidiary of Avista Corp. (approximately 76 percent owned as of December 31, 2010) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Advantage IQ's primary product lines include expense management services for utility, telecom and lease 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 ancillary businesses and investments that include a sheet metal fabrication business, emerging technology venture fund investments and commercial real estate investments, Spokane Energy, LLC (Spokane Energy) (which was consolidated effective January 1, 2010) as well as certain natural gas storage facilities held by Avista Energy, Inc. (Avista Energy). These activities do not represent a reportable business segment and are conducted by various indirect subsidiaries of Avista Corp. 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.

Advantage IQ, Avista Energy, 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 $1,125.8 million as of December 31, 2010, of which $77.7 million represented our investment in Avista Capital.

See "Item 6. Selected Financial Data" and "Note 27 of the Notes to Consolidated Financial Statements" for information with respect to the operating performance of each business segment (and other subsidiaries).

## 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 2010, we supplied retail electric service to 359,000 customers and retail natural gas service to 319,000 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 capacity and energy, and 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 wholesale electric capacity and energy and fuel as part of the process of acquiring and balancing resources to serve our load obligations. These transactions range from terms of one hour up to multiple years. We make continuing projections of:

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

On the basis of these projections, we make purchases and sales of electric capacity and energy 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 $12.8 million in 2010, $9.3 million in 2009 and $9.5 million in 2008.

### Electric Requirements

Our peak electric native load requirement for 2010 occurred on November 23, 2010 at which time our total obligation was 2,507 MW consisting of:

- native load of 1,704 MW,
- long-term wholesale obligations of 237 MW, and
- short-term wholesale obligations of 566 MW.

At that time our maximum resource capacity available was 2,905 MW, which included:

- company-owned electric generation of 1,537 MW,
- long-term hydroelectric contracts with certain Public Utility Districts (PUDs) of 152 MW,
- other long-term wholesale contracts of 563 MW, and
- short-term wholesale purchases of 653 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 2010, 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 2011 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 516 average megawatts (aMW) (or 4.5 million MWhs). Hydroelectric resources provided 476 aMW for 2010, 526 aMW for 2009 and 535 aMW for 2008.

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Noxon Rapids | 1,503 | 1,673 | 1,696 |
| Cabinet Gorge | 942 | 1,061 | 1,081 |
| Post Falls | 90 | 84 | 85 |
| Upper Falls | 71 | 52 | 78 |
| Monroe Street | 106 | 104 | 104 |
| Nine Mile | 101 | 106 | 105 |
| Long Lake | 480 | 487 | 497 |
| Little Falls | 201 | 199 | 205 |
| Total company-owned hydroelectric generation | 3,494 | 3,766 | 3,851 |
| Long-term hydroelectric contracts with PUDs | 685 | 839 | 833 |
| Total hydroelectric generation | 4,179 | 4,605 | 4,684 |

**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.

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Coyote Springs 2 | 1,661 | 1,559 | 1,696 |
| Colstrip | 1,749 | 1,277 | 1,758 |
| Kettle Falls GS | 312 | 184 | 201 |
| Northeast CT and Rathdrum CT | 12 | 44 | 15 |
| Boulder Park and Kettle Falls CT | 14 | 33 | 23 |
| Total thermal generation | 3,748 | 3,097 | 3,693 |

**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. The majority of the rights and obligations under this agreement were conveyed to Shell Energy through the end of 2009. These rights and obligations were conveyed to Avista Corp. (Avista Utilities) beginning in January 2010.

In Idaho, the net costs of the Lancaster power purchase agreement were determined to be prudent by the Idaho Public Utilities Commission (IPUC) and are currently being recovered through general rates and the Power Cost Adjustment mechanism. In Washington, the Washington Utilities and Transportation Commission (WUTC) initially did not allow us to include the costs associated with the power purchase agreement for the Lancaster Plant in rates. We subsequently filed for and received approval for deferred accounting treatment for these net costs. In the 2010 Washington general rate case settlement, the parties agreed that recovery of the deferred net costs associated with the power purchase agreement for the Lancaster Plant would be limited to $6.8 million for 2010. These net deferred costs will be recovered over a five-year amortization period with a rate of return on the unamortized balance. The parties agreed that the costs for the Lancaster Plant for 2011 and going forward are reasonable and should be recovered in rates. As part of the settlement related to the 2010 Lancaster Plant deferred net costs, the parties agreed that there would be no deferrals under the ERM for 2010.

**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 by the Federal Energy Regulatory Commission (FERC) as required by the Energy Policy Act of 2005 (Energy Policy Act), 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 between 2011 and 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 2010, 2009 and 2008.

### 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.

In March 2001, we received a 45-year operating license from the FERC for the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) and the Noxon Rapids Hydroelectric Generating Project (Noxon Rapids). 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 24 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.

We own and operate six hydroelectric plants on the Spokane River. Five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls) are under one FERC license and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The FERC issued a new 50-year license for the Spokane River Project in June 2009. For further information see "Spokane River Licensing" in "Note 24 of the Notes to Consolidated Financial Statements."

### 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 hourly, daily, monthly and annual durations, which vary widely because of the factors that influence demand. Our average hourly load was 1,075 aMW in 2010, 1,082 aMW in 2009 and 1,102 aMW in 2008.

**The following is a forecast of our average annual energy requirements and resources for 2011, 2012, 2013 and 2014:**

**FORECASTED ELECTRIC ENERGY REQUIREMENTS AND RESOURCES (aMW)**

| | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|
| Requirements: | | | | |
| System load | 1,094 | 1,109 | 1,131 | 1,148 |
| Contracts for power sales | 138 | 138 | 124 | 107 |
| Total requirements | 1,232 | 1,247 | 1,255 | 1,255 |
| Resources: | | | | |
| Company-owned and contract hydro generation (1) | 523 | 528 | 533 | 536 |
| Company-owned base load thermal generation (2) | 516 | 494 | 469 | 490 |
| Contracts for power purchases | 376 | 421 | 405 | 422 |
| Total resources | 1,415 | 1,443 | 1,407 | 1,448 |
| Surplus resources | 183 | 196 | 152 | 193 |
| Additional available energy (3) | 144 | 153 | 153 | 153 |
| Total surplus resources | 327 | 349 | 305 | 346 |

*(1) The forecast assumes near normal hydroelectric generation.*

*(2) Excludes the Northeast CT and Rathdrum CT. We generally use these 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 the third quarter of 2009, we filed our 2009 Electric Integrated Resource Plan (IRP) with the WUTC and the IPUC. The IRP identifies a strategic resource portfolio that meets future electric load requirements, promotes environmental stewardship and meets our obligation to provide reliable electric service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project.

Highlights of the 2009 IRP include:

- Up to 150 MW of wind power by 2012,
- An additional 200 MW of wind power by 2022,
- 750 MW of natural gas-fired generation facilities,
- Aggressive energy efficiency measures to reduce generation requirements by 26 percent or 339 MW,
- Transmission upgrades to integrate new generation resources into our system, and
- Hydroelectric upgrades at existing facilities to generate additional renewable energy.

We are required to file an IRP every two years. We will file an IRP in August 2011 and our resource strategy may change from the highlights included above based upon market, legislative and regulatory developments.

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. Our IRP identified that additional qualifying renewable energy is needed by 2016 and that new capacity and energy resources are needed by 2018.

In February 2011, we issued a request for proposals (RFP) seeking qualifying renewable electric resources to meet a portion of our renewable energy portfolio standards requirements under the Washington state Energy Independence Act. We seek to acquire up to 35 aMW of renewable energy, or as much as 100 MW of nameplate wind capacity with deliveries beginning in 2012. We have issued this RFP due to recent market changes, tax incentives that remain in effect and a recent WUTC policy statement indicating support of the acquisition of renewable resources in advance of renewable portfolio standards deadlines, if early acquisition can be cost-justified. We completed the acquisition of the development rights for a wind generation site in 2008. While this RFP does not include the development of this site, we will continue to study this 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 and the purchase of a small amount of renewable energy credits from 2012 through 2015.

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.

**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 also optimize natural gas resources by using excess resources and market opportunities to generate economic value that reduces retail rates. 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. The total volume transported on behalf of our transportation customers for 2010, 2009 and 2008 was 142.1, 144.6 and 148.7 million therms, representing 15 percent, 16 percent and 18 percent of total system deliveries.

**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 249.5 million therms.

Avista Utilities will gain 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 is assigned to Shell Energy through April 30, 2011.

We also contract with Northwest Natural Gas for storage at the Mist Natural Gas storage facility. This contract is for 5 million therms of capacity and up to 150 million therms of deliverability. This contract expires on March 31, 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. 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, operating expenses and revenues as of a date prior to the date of the request. 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.

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 26 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 26 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 26 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.

**Regional Transmission Organizations**

Beginning with FERC Orders No. 888 and No. 2000 (issued in 2000) and continuing with subsequent rulemakings and policies, the FERC has encouraged the formation of various forms of Regional Transmission Organizations (RTOs), including independent system operators (ISOs). While it has not mandated ISO formation, the FERC has issued orders and made public policy statements indicating its support for the development and formation of regional independently-governed transmission 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 RTOs and groups 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 subsequently 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. As of January 2011, the FERC has approved 111 NERC Reliability Standards, including nine 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.

## AVISTA UTILITIES OPERATING STATISTICS

*Avista Corporation*
*Years Ended December 31,*

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Electric Operations** | | | |
| Electric Operating Revenues (Dollars in Thousands): | | | |
| Residential | $ 296,627 | $ 315,649 | $ 279,641 |
| Commercial | 265,219 | 273,954 | 247,714 |
| Industrial | 114,792 | 107,741 | 101,785 |
| Public street and highway lighting | 6,702 | 6,607 | 5,962 |
| Total retail | 683,340 | 703,951 | 635,102 |
| Wholesale | 165,553 | 88,414 | 141,744 |
| Sales of fuel | 106,375 | 32,992 | 44,695 |
| Other | 19,015 | 15,426 | 16,916 |
| Total electric operating revenues | $ 974,283 | $ 840,783 | $ 838,457 |
| Electric Energy Sales (Thousands of MWhs): | | | |
| Residential | 3,618 | 3,791 | 3,744 |
| Commercial | 3,100 | 3,177 | 3,188 |
| Industrial | 2,099 | 1,948 | 2,059 |
| Public street and highway lighting | 26 | 26 | 26 |
| Total retail | 8,843 | 8,942 | 9,017 |
| Wholesale | 3,803 | 2,354 | 1,964 |
| Total electric energy sales | 12,646 | 11,296 | 10,981 |
| Electric Energy Resources (Thousands of MWhs): | | | |
| Hydro generation (from Company facilities) | 3,494 | 3,766 | 3,851 |
| Thermal generation (from Company facilities) | 3,748 | 3,097 | 3,693 |
| Purchased power — hydro generation from long-term contracts with PUDs | 685 | 839 | 833 |
| Purchased power — wholesale | 5,315 | 4,152 | 3,253 |
| Power exchanges | (15) | (18) | (17) |
| Total power resources | 13,227 | 11,836 | 11,613 |
| Energy losses and Company use | (581) | (540) | (632) |
| Total energy resources (net of losses) | 12,646 | 11,296 | 10,981 |
| Number of Electric Retail Customers (Average for Period): | | | |
| Residential | 315,283 | 313,884 | 311,381 |
| Commercial | 39,489 | 39,276 | 39,075 |
| Industrial | 1,376 | 1,394 | 1,388 |
| Public street and highway lighting | 449 | 444 | 434 |
| Total electric retail customers | 356,597 | 354,998 | 352,278 |
| Electric Residential Service Averages: | | | |
| Annual use per customer (KWh) | 11,476 | 12,079 | 12,023 |
| Revenue per KWh (in cents) | 8.20 | 8.33 | 7.47 |
| Annual revenue per customer | $ 940.83 | $ 1,005.62 | $ 898.07 |
| Electric Average Hourly Load (aMW) | 1,075 | 1,082 | 1,102 |

*Avista Corporation*
*Years Ended December 31,*

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Electric Operations (continued):** | | | |
| Resource Availability at time of system peak (MW): | | | |
| Total requirements (winter): | | | |
| Retail native load | 1,704 | 1,763 | 1,821 |
| Wholesale obligations | 803 | 608 | 562 |
| Total requirements (winter) | 2,507 | 2,371 | 2,383 |
| Total resource availability (winter) | 2,905 | 2,514 | 2,480 |
| Total requirements (summer): | | | |
| Retail native load | 1,556 | 1,522 | 1,602 |
| Wholesale obligations | 822 | 685 | 431 |
| Total requirements (summer) | 2,378 | 2,207 | 2,033 |
| Total resource availability (summer) | 2,662 | 2,499 | 2,250 |
| Cooling Degree Days: [1] | | | |
| Spokane, WA | | | |
| Actual | 380 | 589 | 478 |
| 30-year average | 434 | 394 | 394 |
| % of average | 88% | 149% | 121% |

*(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).*

*Avista Corporation*
*Years Ended December 31,*

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Natural Gas Operations** | | | |
| Natural Gas Operating Revenues (Dollars in Thousands): | | | |
| Residential | $ 193,169 | $ 251,022 | $ 276,386 |
| Commercial | 98,257 | 135,236 | 152,147 |
| Industrial and interruptible | 6,494 | 9,945 | 12,159 |
| Total retail | 297,920 | 396,203 | 440,692 |
| Wholesale | 197,364 | 143,524 | 281,668 |
| Transportation | 6,470 | 6,067 | 6,327 |
| Other | 9,495 | 8,624 | 5,520 |
| Total natural gas operating revenues | $ 511,249 | $ 554,418 | $ 734,207 |
| Therms Delivered (Thousands of Therms): | | | |
| Residential | 188,546 | 207,979 | 210,125 |
| Commercial | 113,422 | 126,345 | 128,224 |
| Industrial and interruptible | 9,755 | 10,918 | 12,196 |
| Total retail | 311,723 | 345,242 | 350,545 |
| Wholesale | 468,887 | 397,977 | 345,916 |
| Transportation | 142,093 | 144,580 | 148,723 |
| Interdepartmental and Company use | 393 | 502 | 526 |
| Total therms delivered | 923,096 | 888,301 | 845,710 |
| Sources of Natural Gas Supply (Thousands of Therms): | | | |
| Purchases | 787,836 | 751,057 | 710,137 |
| Storage — injections | (86,750) | (99,330) | (76,491) |
| Storage — withdrawals | 83,333 | 95,183 | 66,271 |
| Natural gas for transportation | 142,093 | 144,580 | 148,723 |
| Distribution system losses | (3,416) | (3,189) | (2,930) |
| Total natural gas supply | 923,096 | 888,301 | 845,710 |
| Number Of Natural Gas Retail Customers (Average for Period): | | | |
| Residential | 282,721 | 280,667 | 277,892 |
| Commercial | 33,431 | 33,214 | 32,901 |
| Industrial and interruptible | 292 | 300 | 297 |
| Total natural gas retail customers | 316,444 | 314,181 | 311,090 |
| Natural Gas Residential Service Averages: | | | |
| Annual use per customer (therms) | 667 | 741 | 756 |
| Revenue per therm (in dollars) | $ 1.02 | $ 1.21 | $ 1.32 |
| Annual revenue per customer | $ 683.25 | $ 894.37 | $ 994.58 |
| Heating Degree Days: (1) | | | |
| Spokane, WA | | | |
| Actual | 6,320 | 6,976 | 7,052 |
| 30-year average | 6,647 | 6,820 | 6,820 |
| % of average | 95% | 102% | 103% |
| Medford, OR | | | |
| Actual | 4,119 | 4,485 | 4,569 |
| 30-year average | 4,402 | 4,533 | 4,533 |
| % of average | 94% | 99% | 101% |

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

## ADVANTAGE IQ

Our subsidiary, Advantage IQ provides sustainable utility expense management and energy management solutions to multi-site companies across North America. Advantage IQ'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, Advantage IQ analyzes and audits invoices, then presents consolidated bills on-line, and processes payments. Information gathered from invoices, providers and other customer-specific data allows Advantage IQ to provide its clients with in-depth analytical support, real-time reporting and consulting services.

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

Advantage IQ 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 any claimed or threatened infringement on any of Advantage IQ'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.

**The following table presents key statistics for Advantage IQ:**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Customers at year-end | 534 | 532 | 537 |
| Billed sites at year-end | 360,596 | 421,080 | 417,078 |
| Dollars of customer bills processed (in billions) | $ 17.3 | $ 17.4 | $ 16.7 |

The decrease in billed sites at year-end 2010 as compared to prior periods 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, Advantage IQ acquired substantially all of the assets and liabilities of The Loyalton Group, a Minneapolis-based energy management firm known for its energy procurement and price risk management solutions. In January 2011, Advantage IQ acquired substantially all of the assets and liabilities of Building Knowledge Networks, a Seattle-based real-time building energy management services provider.

## OTHER BUSINESSES

Avista Energy still owns natural gas storage facilities and we expect these assets to be transferred to our utility operations on May 1, 2011. This business had operating revenues and resource costs through the end of 2009 related to the power purchase agreement for the Lancaster Plant. The rights and obligations related to the power purchase agreement for the Lancaster Plant were conveyed to Avista Corp. (Avista Utilities) in January 2010.

The implementation of amendments to accounting standards (See Note 2 of the Notes to Consolidated Financial Statements) resulted in the Company including Spokane Energy in its consolidated financial statements effective January 1, 2010. 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. The consolidation of Spokane Energy results in an increase in operating revenues, operating expenses and interest expense with no impact on net income.

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 low income housing, 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.

## 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.

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.

**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, 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 base 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 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.

**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 (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. In February 2011, we entered into a new $400 million committed line of credit, which is scheduled to expire in February 2015. We cannot guarantee that we will have access to credit beyond the expiration date. The line of credit agreements contain customary covenants and default provisions. In the event of default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock.

**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 common to 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,
- cyber security attacks or other disruptions to our information systems and other administrative resources required for normal operations,
- explosions, fires, accidents, or mechanical breakdowns that may occur while operating and maintaining our generation, transmission and distribution systems,
- natural disasters that can disrupt energy generation, transmission and distribution, and
- terrorism and other malicious threats.

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 their obligations to us.

**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 24 of the Notes to Consolidated Financial Statements" for further information. Any potential refunds or obligations arising from western energy market issues (or any other contingent matters) were retained by Avista Energy as part of its asset sale agreement in June 2007.

**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 and the EPA. 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, and
- require construction of specific types of generation plants at higher cost.

**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 24 of the Notes to Consolidated Financial Statements" for further details of these matters including:

- a potential liability related to 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) | 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[3] | 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 |

*(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, 2010.*

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

**Electric Distribution and Transmission Plant**

We operate approximately 18,200 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 Lancaster Plant, 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. These interconnections also serve as points of delivery for power from generating facilities outside of our service area, including:

- Colstrip,
- Coyote Springs 2, and
- Mid-Columbia hydroelectric generating facilities.

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 and Kettle Falls projects. 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 contract 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 50 miles in Oregon. Our natural gas system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

We own a one-third interest in 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 249.5 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 will gain 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 is assigned to Shell Energy through April 30, 2011.

## ITEM 3. LEGAL PROCEEDINGS

See "Note 24 of Notes to Consolidated Financial Statements" for information with respect to legal proceedings.

## ITEM 4. (REMOVED AND RESERVED)

# 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. As of January 31, 2011, there were 11,102 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 4, 2011, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.275 per share on the Company's common stock. This was an increase of $0.025 per share, or 10 percent from the previous quarterly dividend of $0.25 per share.

For additional information, refer to "Notes 1, 21, 22 and 23 of Notes to Consolidated Financial Statements."

**The following table presents quarterly high and low stock prices, as well as dividend information:**

| | Three Months Ended | | | |
|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 |
| **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 |
| **2009** | | | | |
| Dividends paid per common share | $ 0.18 | $ 0.21 | $ 0.21 | $ 0.21 |
| Trading price range per common share: | | | | |
| High | $ 20.01 | $ 18.13 | $ 20.83 | $ 22.44 |
| Low | $ 12.67 | $ 13.44 | $ 17.59 | $ 18.48 |

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

## ITEM 6.

## SELECTED FINANCIAL DATA

*Avista Corporation*
*(in thousands, except per share data and ratios)*
*Years Ended December 31,*

| | 2010 | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| **Operating Revenues:** | | | | | |
| Avista Utilities | $ 1,419,646 | $ 1,395,201 | $ 1,572,664 | $ 1,288,363 | $ 1,267,938 |
| Advantage IQ | 102,035 | 77,275 | 59,085 | 47,255 | 39,636 |
| Other | 61,067 | 40,089 | 45,014 | 82,139 | 198,737 |
| Intersegment eliminations | (24,008) | — | — | — | — |
| Total | $ 1,558,740 | $ 1,512,565 | $ 1,676,763 | $ 1,417,757 | $ 1,506,311 |
| **Income (Loss) from Operations (pre-tax):** | | | | | |
| Avista Utilities | $ 208,104 | $ 195,389 | $ 174,245 | $ 150,053 | $ 177,049 |
| Advantage IQ | 15,865 | 11,603 | 11,297 | 11,012 | 10,479 |
| Other | 6,219 | (6,334) | (631) | (22,636) | 12,032 |
| Total | $ 230,188 | $ 200,658 | $ 184,911 | $ 138,429 | $ 199,560 |
| Net income | $ 94,948 | $ 88,648 | $ 74,757 | $ 38,727 | $ 72,941 |
| Net income attributable to noncontrolling interests | $ (2,523) | $ (1,577) | $ (1,137) | $ (252) | $ — |
| **Net Income (Loss) Attributable to Avista Corporation:** | | | | | |
| Avista Utilities | $ 86,681 | $ 86,744 | $ 70,032 | $ 43,822 | $ 57,794 |
| Advantage IQ | 7,433 | 5,329 | 6,090 | 6,651 | 6,255 |
| Other | (1,689) | (5,002) | (2,502) | (11,998) | 8,892 |
| Total | $ 92,425 | $ 87,071 | $ 73,620 | $ 38,475 | $ 72,941 |
| Average common shares outstanding, basic | 55,595 | 54,694 | 53,637 | 52,796 | 49,162 |
| Average common shares outstanding, diluted | 55,824 | 54,942 | 54,028 | 53,263 | 49,897 |
| Common shares outstanding at year-end | 57,120 | 54,837 | 54,488 | 52,909 | 52,514 |
| **Earnings per Common Share Attributable to Avista Corporation:** | | | | | |
| Diluted | $ 1.65 | $ 1.58 | $ 1.36 | $ 0.72 | $ 1.46 |
| Basic | $ 1.66 | $ 1.59 | $ 1.37 | $ 0.73 | $ 1.48 |
| Dividends paid per common share | $ 1.000 | $ 0.810 | $ 0.690 | $ 0.595 | $ 0.570 |
| Book value per common share at year-end | $ 19.71 | $ 19.17 | $ 18.30 | $ 17.27 | $ 17.41 |
| **Total Assets at Year-End:** | | | | | |
| Avista Utilities | $ 3,589,235 | $ 3,400,384 | $ 3,434,844 | $ 3,009,499 | $ 2,895,883 |
| Advantage IQ | 221,086 | 143,060 | 125,911 | 108,929 | 100,431 |
| Other | 129,774 | 63,515 | 69,992 | 71,369 | 1,060,194 |
| Total | $ 3,940,095 | $ 3,606,959 | $ 3,630,747 | $ 3,189,797 | $ 4,056,508 |
| Long-Term Debt (including current portion) | $ 1,101,857 | $ 1,071,338 | $ 826,465 | $ 948,833 | $ 976,459 |
| Nonrecourse Long-Term Debt of Spokane Energy (including current portion) (1) | $ 58,934 | $ — | $ — | $ — | $ — |
| Long-Term Debt to Affiliated Trusts | $ 51,547 | $ 51,547 | $ 113,403 | $ 113,403 | $ 113,403 |
| Preferred Stock Subject to Mandatory Redemption | $ — | $ — | $ — | $ — | $ 26,250 |
| Total Avista Corporation Stockholders' Equity | $ 1,125,784 | $ 1,051,287 | $ 996,883 | $ 913,966 | $ 914,525 |
| Ratio of Earnings to Fixed Charges (2) | 2.86 | 2.95 | 2.43 | 1.67 | 2.14 |

*(1) Spokane Energy was consolidated effective January 1, 2010. See Note 2 of the Notes to Consolidated Financial Statements.*

*(2) See Exhibit 12 for computations.*

## 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.
- **Advantage IQ** — an indirect subsidiary of Avista Corp. (approximately 76 percent owned as of December 31, 2010) provides energy efficiency and cost management programs and services for multi-site customers and utilities throughout North America. Advantage IQ's primary product lines include expense management services for utility, telecom and lease 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 (which was consolidated effective January 1, 2010) as well as certain natural gas storage facilities held by Avista Energy. 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 Corporation for each of our business segments (and the other businesses) for the year ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Avista Utilities | $ 86,681 | $ 86,744 | $ 70,032 |
| Advantage IQ | 7,433 | 5,329 | 6,090 |
| Other | (1,689) | (5,002) | (2,502) |
| Net income attributable to Avista Corporation | $ 92,425 | $ 87,071 | $ 73,620 |

### EXECUTIVE LEVEL SUMMARY

#### Overall

Net income attributable to Avista Corporation was $92.4 million for 2010, an increase from $87.1 million for 2009. This was primarily due to an increase in earnings at Advantage IQ and a decrease in the net loss from the other businesses. Earnings at Avista Utilities were positively impacted by general rate increases, offset by warmer weather in the heating season and an increase in interest expense, other operating expenses and depreciation and amortization.

#### Avista Utilities

Avista Utilities is our most significant business segment. Our utility operating and 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 continue to execute our regulatory strategy to 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 infrastructure. We filed general rate increase requests in each of our jurisdictions in 2010. General rate increases went into effect in Idaho on October 1, 2010 and in Washington effective January 1, 2010 and December 1, 2010. In February 2011, we reached an all-party settlement in Oregon for a general rate increase that is subject to approval by the OPUC.

Our utility net income was $86.7 million for 2010 and 2009. Earnings for 2010 were positively impacted by an increase in gross margin (operating revenues less resource costs). The increase in gross margin was primarily due to general rate increases and power supply costs below the amount included in base retail rates in Washington, partially offset by lower retail loads (particularly for natural gas) caused by warmer weather during the heating season. The increase in gross margin was offset by an increase in interest expense, other operating expenses and depreciation and amortization.

We are continuing to invest in generation, transmission and distribution systems to enhance service reliability for our customers and replace aging infrastructure. Utility capital expenditures were $202.2 million for 2010. We expect utility capital expenditures to be about $250 million for 2011. These estimates of capital expenditures are subject to continuing review and adjustment (see discussion at "Avista Utilities Capital Expenditures").

#### Advantage IQ

Advantage IQ had net income attributable to Avista Corporation of $7.4 million for 2010, an increase from $5.3 million for 2009. The increase was primarily due to moderate growth from expense management and energy management services coupled with the acquisition of Ecos Consulting, Inc. (Ecos) effective August 31, 2009. Advantage IQ's earnings potential continues to be moderated by low short-term interest rates, which limits interest revenue on funds held for customers.

On December 31, 2010, Advantage IQ acquired substantially all of the assets and liabilities of The Loyalton Group, a Minneapolis-based energy management firm known for its energy procurement and price risk management solutions. The acquisition of The Loyalton Group was funded through available cash at Advantage IQ.

In January 2011, Advantage IQ acquired substantially all of the assets and liabilities of Building Knowledge Networks, a Seattle-based real-time building energy management services provider. The acquisition of Building Knowledge Networks was funded through available cash at Advantage IQ.

Effective July 2, 2008, Advantage IQ acquired Cadence Network, a Cincinnati, Ohio-based energy and expense management company. As consideration, the owners of Cadence Network received a 25 percent ownership interest in Advantage IQ through the issuance of Advantage IQ common stock. The previous owners of Cadence Network can exercise a right to have their shares of Advantage IQ stock redeemed by Advantage IQ during July 2011 or July 2012 if Advantage IQ is not liquidated through either an initial public offering or sale of the business to a third party. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Advantage IQ at the time of the redemption election as determined by certain independent parties. As of December 31, 2010, there were redeemable noncontrolling interests of $38.1 million related to these redemption rights. Should the previous owners of Cadence Network exercise their redemption rights, Advantage IQ 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, the other owners of Advantage IQ (including Avista Capital) purchased shares held by the one of the previous owners of Cadence Network (that owned 4.5 percent of Advantage IQ). Avista Capital's portion of the purchase was $5.6 million.

We may seek to monetize all or part of our investment in Advantage IQ in the future, regardless of whether Advantage IQ'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 Advantage IQ. There can be no assurance that such a transaction will be completed.

**Other Businesses**

The net loss for these operations was $1.7 million for 2010 compared to a net loss of $5.0 million for 2009. The improvement in results was due in part to increased earnings at METALfx and reduced litigation costs related to the remaining contracts and previous operations of Avista Energy. In 2010, we recorded a $2.2 million impairment of our investment in a fuel cell business that was previously a subsidiary of the Company. Also, in 2009 we recorded a $3.0 million impairment of a commercial building.

**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.

At December 31, 2010, we had a committed line of credit in the total amount of $320.0 million with an expiration date of April 5, 2011 under which there were $110.0 million of cash borrowings and $27.1 million in letters of credit outstanding. We also had a committed line of credit in the total amount of $75.0 million with an expiration date of April 5, 2011 under which there were no borrowings outstanding as of December 31, 2010.

As of December 31, 2010, we had a combined $257.9 million of available liquidity under our $320.0 million and $75.0 million committed lines of credit.

In February 2011, we entered into a new committed line of credit 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.

In December 2010, we elected to terminate our $50.0 million accounts receivable financing facility prior to its scheduled termination date of March 2011 based on our forecasted liquidity needs. We did not borrow any funds under this facility during 2010.

In December 2010, we issued $52.0 million of 3.89 percent First Mortgage Bonds due in 2020 and $35.0 million of 5.55 percent First Mortgage Bonds due in 2040. The total net proceeds from the sale of the new bonds of $86.6 million (net of placement agent fees and before our expenses) were used to redeem $45.0 million of 6.125 percent First Mortgage Bonds due in December 2013 and $30.0 million of 7.25 percent First Mortgage Bonds due in September 2013. These First Mortgage Bonds were redeemed at par plus a make-whole redemption premium of $10.7 million. In accordance with regulatory accounting practices, the make-whole redemption premium will be amortized over the life of the new debt issued.

Also in December 2010, we issued $50.0 million of 1.68 percent First Mortgage Bonds due in 2013. The net proceeds from the issuance of the Bonds of $49.8 million (net of placement agent fees and before our expenses) were used to repay a portion of the borrowings outstanding under our committed line of credit.

We are planning, subject to market conditions, to cause the redemption of $83.7 million of Pollution Control Bonds and the refunding thereof with new bond issues in 2011. We are currently the holder of all bonds to be redeemed and refunded and, accordingly, would receive the redemption proceeds.

We are party to a sales agency agreement under which we sell shares of our common stock from time to time. In 2010, we sold 2.1 million shares for a total of $43.2 million. As of December 31, 2010, we had 1.0 million shares available to be issued under this agreement.

We expect to issue up to $25 million of common stock in 2011 in order to maintain our capital structure at an appropriate level for our business. After considering the issuances of common stock during 2011, we expect net cash flows from operating activities, together with cash available under our new $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
- move our earned returns closer to those 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 plan to file general rate cases in Washington and Idaho in the first half of 2011.

**The following is a summary of our authorized rates of return in each jurisdiction:**

| Jurisdiction and service | Implementation Date | Authorized Overall Rate of Return | Authorized Return on Equity | Authorized Equity Level |
|---|---|---|---|---|
| Washington electric and natural gas | December 2010 | 7.91% | 10.2% | 46.5% |
| Idaho electric and natural gas | October 2010 | (1) | (1) | (1) |
| Oregon natural gas | November 2009 | 8.19% | 10.1% | 50.0% |

(1) *The rate adjustment implemented on October 1, 2010 resulting from the Idaho electric and natural gas general rate case settlement did not have a specific authorized rate of return, return on equity or equity level. The prior rate case settlement implemented in August 2009 had an authorized rate of return of 8.55 percent, a return on equity of 10.5 percent and authorized equity level of 50.0 percent.*

### Washington General Rate Cases

In September 2008, we entered into a settlement stipulation in our general rate case that was filed with the WUTC in March 2008. This settlement stipulation was approved by the WUTC in December 2008. The new electric and natural gas rates became effective on January 1, 2009. As agreed to in the settlement, base electric rates for our Washington customers increased by an average of 9.1 percent, which was designed to increase annual revenues by $32.5 million. Base natural gas rates for our Washington customers increased by an average of 2.4 percent, which was designed to increase annual revenues by $4.8 million.

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 this general rate case order, the WUTC did not allow us to include the costs associated with the power purchase agreement for the Lancaster Plant in rates. We subsequently filed for and received approval for deferred accounting treatment for these net costs.

In August 2010, we entered into an all-party settlement stipulation in our general rate case filed with the WUTC in March 2010. This settlement stipulation was approved by the WUTC in November 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. As part of the settlement, the parties agreed that Avista Corp. would not file a general rate case in the Washington jurisdiction before April 1, 2011.

The parties agreed that recovery of the deferred net costs associated with the power purchase agreement for the Lancaster Plant were limited to $6.8 million for 2010. These net deferred costs will be recovered over a five-year amortization period with a rate of return on the unamortized balance. The parties agreed that the costs for the Lancaster Plant for 2011 and going forward are reasonable and should be recovered in rates.

As part of the settlement related to the 2010 Lancaster Plant deferred net costs, the parties agreed that there would be no deferrals under the ERM for 2010 in either the surcharge or rebate direction. For 2010, we received all of the benefit from the amount of power supply costs below the level in retail rates in Washington. Deferrals under the ERM will resume in 2011. The net effect of the settlement for the Lancaster Plant deferrals and the ERM was slightly positive to 2010 earnings.

### Idaho General Rate Cases

In August 2008, we entered into an all-party settlement stipulation in our electric and natural gas general rate cases that were filed with the IPUC in April 2008. This settlement stipulation was approved by the IPUC in September 2008. The new electric and natural gas rates became effective on October 1, 2008. As agreed to in the settlement, base electric rates for our Idaho customers increased by an average of 12.0 percent, which was designed to increase annual revenues by $23.2 million. Base natural gas rates for our Idaho customers increased by an average of 4.7 percent, which was designed to increase annual revenues by $3.9 million.

In June 2009, we entered into an all-party settlement stipulation in our electric and natural gas general rate cases that were filed with the IPUC in January 2009. This settlement stipulation was approved by the IPUC in July 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. Offsetting the base electric rate increase was an overall

4.2 percent decrease in the Power Cost Adjustment (PCA) surcharge, which was designed to decrease annual PCA revenues by $9.3 million, resulting in a net increase in annual revenues of $3.2 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. Offsetting the natural gas rate increase for residential customers was an equivalent Purchased Gas Adjustment (PGA) decrease of 2.1 percent. Large general services customers received a PGA decrease of 2.4 percent and interruptible services customers received a PGA decrease of 2.8 percent. The overall PGA decrease resulted in a $2.0 million decrease in annual PGA revenues, resulting in a net decrease in annual revenues of $0.1 million. The PGAs are designed to pass through changes in natural gas costs to our customers with no change in gross margin or net income.

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 includes a rate mitigation plan under which the impact on customers of the new rates is 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 will increase on October 1, 2011 and October 1, 2012 as the previous deferred state income tax balance is amortized to zero.

**Oregon General Rate Cases**

As approved by the OPUC in March 2008, natural gas rates for our Oregon customers increased 0.4 percent effective April 1, 2008 (designed to increase annual revenues by $0.5 million) and increased an additional 1.1 percent effective November 1, 2008 (designed to increase annual revenues by an additional $1.4 million).

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 February 2011, we entered into an all-party settlement stipulation in our general rate case that was filed with the OPUC in September 2010. The settlement, which is subject to approval by the OPUC, 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 would become effective March 15, 2011, with the remaining increase effective June 1, 2011. The settlement is based on an overall rate of return of 8.0 percent, with a common equity ratio of 50.0 percent and a 10.1 percent return on equity. Our original request was for an overall rate increase of 5.6 percent, designed to increase annual revenues by $5.4 million. Our original request was based on an overall rate of return of 8.61 percent, with a common equity ratio of 50.8 percent and a 10.9 percent return on equity.

**Purchased Gas Adjustments**

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. PGAs are designed to pass through changes in natural gas costs to our customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, we absorb (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 $22.1 million as of December 31, 2010, a decrease from $40.0 million as of December 31, 2009.

**Oregon Senate Bill 408**

The OPUC established rules in September 2007 related to Oregon Senate Bill 408 (OSB 408), which was enacted into law in 2005. These rules direct the utility to establish an automatic adjustment clause to account for the difference between income taxes collected in rates and taxes paid to units of government, net of adjustments, when that difference exceeds $100,000. The automatic adjustment clause may result in either rate increases or rate decreases.

We recorded a potential refund liability for the 2009 tax report of $1.2 million (including interest). In October 2010, we filed the tax report for 2009 showing taxes collected to be less than taxes paid by $1.3 million before interest that would result in a surcharge (rate increase) for Oregon customers. The filing relied upon a deferred tax floor provision of the rules. In December 2010, we were notified by OPUC Staff that, although they agreed that our filing complied with the existing rules, an immediate rulemaking was necessary to eliminate the deferred tax floor provision that we used. In February 2011, we entered into a settlement stipulation that, if approved by the OPUC, would refund $1.2 million to Oregon customers for the 2009 tax report year.

**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. Deferrals under the ERM will resume in 2011.

In periods where we are a net seller of wholesale power, market prices lower than the prices included in rates negatively impact the ERM. In periods where we are a net purchaser, market prices lower than the amount included in retail rates have a beneficial impact under the ERM. This difference in net power supply costs 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, 90 percent of the cost variance is deferred for future surcharge or rebate. We absorb into power supply costs the remaining 10 percent of the annual variance beyond $10.0 million.

**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% |

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.

In February 2010, the WUTC approved our request to eliminate the ERM surcharge. The surcharge was eliminated as the previous balance of deferred power costs was recovered. This resulted in a rate reduction of 7 percent for our Washington customers with no impact on our income from operations or net income.

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 costs deferred during the preceding July—June twelve-month period. The PCA rate surcharge was 0.61 cents per KWh for the period October 1, 2008 through September 30, 2009. However, the surcharge rate was lowered to 0.344 cents per KWh on August 1, 2009 to help mitigate the impact of the general rate increase that was also effective on that date. In September 2010, the IPUC approved our request to increase the PCA surcharge rate to 0.532 cents per KWh effective October 1, 2010.

**The following table shows activity in deferred power costs for Washington and Idaho during 2009 and 2010 (dollars in thousands):**

| | Washington | Idaho | Total |
|---|---|---|---|
| Deferred power costs as of December 31, 2008 | $ 36,952 | $ 20,655 | $ 57,607 |
| Activity from January 1 — December 31, 2009: | | | |
| Power costs deferred | — | 17,985 | 17,985 |
| Interest and other net additions | 879 | 388 | 1,267 |
| Recovery of deferred power costs through retail rates | (31,567) | (17,521) | (49,088) |
| Deferred power costs as of December 31, 2009 | 6,264 | 21,507 | 27,771 |
| Activity from January 1 — December 31, 2010: | | | |
| Power costs deferred | — | 9,768 | 9,768 |
| Interest and other net additions | 538 | 26 | 564 |
| Recovery of deferred power costs through retail rates | (6,802) | (12,996) | (19,798) |
| Deferred power costs as of December 31, 2010 | $ — | $ 18,305 | $ 18,305 |

**Natural Gas Transmission**

In response to recent natural gas pipeline incidents (not within our service territory), members of the United States Congress are proposing various additional regulations to address public safety concerns. Regulations have been proposed to require automatic shut-off valves on pipeline mains; increase installation of excess flow valves on gas service piping, increase "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.

In addition, the Pipeline and Hazardous Materials Safety Administration issued an Advisory Bulletin on January 4, 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 of 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, Advantage IQ and the other businesses) that follow this section.

### 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 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 and prices resulting from the elimination of the ERM surcharge, 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 energy revenues decreased $4.4 million to $20.0 million. These revenues for 2010 primarily represent revenues for Spokane Energy (which was consolidated effective January 1, 2010) related to a long-term electric capacity contract. These revenues for 2009 primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of 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.

Other non-utility revenues increased $27.9 million to $120.9 million primarily as a result of an Advantage IQ'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. Revenues from our other businesses increased $3.2 million, primarily due to increased sales at METALfx.

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 (reflecting an increase in thermal generation optimization activities).

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.

Non-utility resource costs decreased $12.0 million. These costs for 2010 primarily represent expenses for Spokane Energy (which was consolidated effective January 1, 2010) related to a long-term electric capacity contract. These costs for 2009 primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of 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.

Other non-utility operating expenses increased $15.9 million reflecting an increase of $19.1 million for Advantage IQ 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. The increase was partially offset by decreased operating expenses from the other businesses due to an impairment of a commercial building of $3.0 million in 2009.

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.

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 that was previously a subsidiary of the Company.

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).

### 2009 compared to 2008

Utility revenues decreased $177.5 million to $1,395.2 million due to decreased natural gas revenues of $179.8 million, partially offset by increased electric revenues of $2.3 million. Wholesale natural gas revenues decreased $138.1 million (due to decreased prices, offset by increased volumes) and retail natural gas revenues decreased $44.5 million (primarily due to decreased prices and partially due to decreased volumes). Retail electric revenues increased $68.8 million (primarily due to the Washington general rate increase implemented on January 1, 2009 and the Idaho general rate increases implemented on October 1, 2008 and August 1, 2009), while wholesale electric revenues decreased $53.3 million (due to a decrease in prices, partially offset by an increase in volumes) and sales of fuel decreased $11.7 million.

Non-utility energy marketing and trading revenues decreased $0.8 million to $24.4 million. These revenues primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were conveyed to Shell Energy through the end of 2009. These rights and obligations were conveyed to our utility operations in January 2010.

Other non-utility revenues increased $14.1 million to $92.9 million as a result of an increase in revenues from Advantage IQ of $18.2 million primarily due to the acquisition of Cadence Network in the third quarter of 2008 and Ecos in the third quarter of 2009, as well as other customer billing services. These increases in revenues from Advantage IQ were partially offset by a decrease in interest earnings on funds held for customers (due to lower interest rates). The increase in revenues at Advantage IQ was partially offset by decreased revenues from our other businesses of $4.1 million, primarily due to decreased sales at METALfx.

Utility resource costs decreased $232.5 million due to decreases in natural gas resource costs of $186.1 million and electric resource costs of $46.3 million. The decrease in natural gas resource costs primarily reflects a decrease in the price of natural gas purchases. The decrease in electric resource costs was primarily due to a decrease in fuel costs (due to a decrease in thermal generation and natural gas fuel prices).

Utility other operating expenses increased $23.4 million primarily due to an $8.9 million increase in electric generation operating and maintenance expenses, a $4.3 million increase in natural gas distribution and service costs, as well as a $10.7 million increase in pension and other benefit costs.

Utility depreciation and amortization increased $5.9 million primarily due to additions to utility plant.

Utility taxes other than income taxes increased $4.5 million due to increased revenue related taxes and increased property taxes.

Non-utility resource costs decreased $0.1 million. These costs primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were conveyed to Shell Energy through the end of 2009. These rights and obligations were conveyed to our utility operations in January 2010.

The net change in other non-utility operating expenses was an increase of $17.6 million due to an increase of $16.6 million for Advantage IQ primarily due to the acquisition of Cadence Network in the third quarter of 2008 and the acquisition of Ecos in the third quarter of 2009. The increase was also partially due to an impairment of a commercial building of $3.0 million in the other businesses. These increases were partially offset by decreased operating expenses from METALfx.

Interest expense decreased $8.4 million due to the effect of long-term debt maturities and redemptions during 2008, which were funded primarily with proceeds from the issuance of long-term debt as well as borrowings under our committed line of credit at lower interest rates. The decrease was also partially due to interest expense of $1.4 million related to an income tax settlement recorded in the third quarter of 2008.

Interest expense to affiliated trusts decreased $4.2 million due to the redemption of $61.9 million of long-term debt due to affiliated trusts in April 2009 and a decrease in the variable interest rate.

Capitalized interest decreased $4.1 million primarily due to a decrease in the effective borrowing rate used to compute capitalized interest, as the average balance outstanding under our committed line of credit was significantly higher in 2009 as compared to 2008.

Other income-net decreased $9.6 million due to a decrease in interest income (primarily due to $5.7 million of interest income recorded on the IRS settlement agreement in the third quarter of 2008). The decrease was also due to a decrease in equity-related AFUDC.

Income taxes increased $0.7 million and our effective tax rate was 34.3 percent for 2009 compared to 37.9 percent for 2008. The decrease in our effective tax rate was primarily due to adjustments related to IRS audits and adjustments for the 2008 filed federal tax return. In total, these adjustments (recorded in the third quarter of 2009) had a favorable impact to recorded income tax expense of $3.2 million (Avista Utilities).

## AVISTA UTILITIES

### 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 |

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 as sales of fuel. 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 |

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). Wholesale sales reflect the sale of natural gas in excess of load requirements as part of the natural gas procurement and resource optimization process. Part of the increase in the volume of wholesale natural gas sales reflects lower than expected retail loads 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. Additionally, we engage in optimization of available interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. With lower retail loads in 2010 as compared to 2009, we had more opportunity to optimize transportation resources. 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.

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 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. 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.

### 2009 compared to 2008

Net income for the utility was $86.7 million for 2009 compared to $70.0 million for 2008. Utility income from operations was $195.4 million for 2009 compared to $174.2 million for 2008. This increase in income from operations was primarily due to increased gross margin (operating revenues less resource costs). This was partially offset by an increase in other utility operating expenses, depreciation and amortization, and taxes other than income taxes.

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

| | Electric | | Natural Gas | | Total | |
|---|---|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 | 2009 | 2008 |
| Operating revenues | $ 840,783 | $ 838,457 | $ 554,418 | $ 734,207 | $ 1,395,201 | $ 1,572,664 |
| Resource costs | 379,058 | 425,373 | 420,481 | 606,616 | 799,539 | 1,031,989 |
| Gross margin | $ 461,725 | $ 413,084 | $ 133,937 | $ 127,591 | $ 595,662 | $ 540,675 |

Utility operating revenues decreased $177.5 million and resource costs decreased $232.5 million, which resulted in an increase of $55.0 million in gross margin. The gross margin on electric sales increased $48.6 million and the gross margin on natural gas sales increased $6.3 million. The increase in our electric and natural gas gross margin was primarily due to general rate increases in Washington effective January 1, 2009 and Idaho effective October 1, 2008 and August 1, 2009. We had a benefit of $3.0 million under the ERM in 2009 compared to an expense of $7.4 million in 2008.

**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 | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| Residential | $ 315,649 | $ 279,641 | 3,791 | 3,744 |
| Commercial | 273,954 | 247,714 | 3,177 | 3,188 |
| Industrial | 107,741 | 101,785 | 1,948 | 2,059 |
| Public street and highway lighting | 6,607 | 5,962 | 26 | 26 |
| Total retail | 703,951 | 635,102 | 8,942 | 9,017 |
| Wholesale | 88,414 | 141,744 | 2,354 | 1,964 |
| Sales of fuel | 32,992 | 44,695 | — | — |
| Other | 15,426 | 16,916 | — | — |
| Total | $ 840,783 | $ 838,457 | 11,296 | 10,981 |

Retail electric revenues increased $68.8 million due to an increase in revenue per MWh (increased revenues $74.7 million) primarily due to the Washington general rate increase implemented on January 1, 2009 and the Idaho general rate increases implemented on October 1, 2008 and August 1, 2009, offset by a decrease in total MWhs sold (decreased revenues $5.9 million) primarily due to a decrease in use per customer (commercial and industrial).

Wholesale electric revenues decreased $53.3 million due to a decrease in sales prices (decreased revenues $68.0 million), offset by an increase in sales volumes (increased revenues $14.7 million). The increase in sales volume primarily relates to resource optimization activities.

Sales of fuel decreased $11.7 million due to a decrease in thermal generation resource optimization activities and lower natural gas prices in 2009 as compared to 2008.

**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 | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| Residential | $ 251,022 | $ 276,386 | 207,979 | 210,125 |
| Commercial | 135,236 | 152,147 | 126,345 | 128,224 |
| Interruptible | 4,709 | 5,428 | 5,360 | 5,758 |
| Industrial | 5,236 | 6,731 | 5,558 | 6,438 |
| Total retail | 396,203 | 440,692 | 345,242 | 350,545 |
| Wholesale | 143,524 | 281,668 | 397,977 | 345,916 |
| Transportation | 6,067 | 6,327 | 144,580 | 148,723 |
| Other | 8,624 | 5,520 | 502 | 526 |
| Total | $ 554,418 | $ 734,207 | 888,301 | 845,710 |

Retail natural gas revenues decreased $44.5 million due to a decrease in volumes (decreased revenues $6.1 million), and lower retail rates (decreased revenues $38.4 million). We sold less retail natural gas in 2009 as compared to 2008, primarily due to warmer weather, as well as a decrease in commercial and industrial use per customer. The decrease in retail rates reflects the purchased gas adjustments implemented in 2009 offset by the Washington general rate increase implemented on January 1, 2009 and Idaho general rate increases implemented on October 1, 2008 and August 1, 2009.

Wholesale natural gas revenues decreased $138.1 million due to a decrease in prices (decreased revenues $156.9 million), partially offset by an increase in volumes (increased revenues $18.8 million).

**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 | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| Residential | 313,884 | 311,381 | 280,667 | 277,892 |
| Commercial | 39,276 | 39,075 | 33,214 | 32,901 |
| Interruptible | — | — | 42 | 40 |
| Industrial | 1,394 | 1,388 | 258 | 257 |
| Public street and highway lighting | 444 | 434 | — | — |
| Total retail customers | 354,998 | 352,278 | 314,181 | 311,090 |

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

| | 2009 | 2008 |
|---|---|---|
| Electric resource costs: | | |
| Power purchased | $ 193,683 | $ 193,924 |
| Power cost amortizations, net | 31,102 | 25,464 |
| Fuel for generation | 89,602 | 134,446 |
| Other fuel costs | 31,881 | 43,103 |
| Other regulatory amortizations, net | 19,602 | 10,490 |
| Other electric resource costs | 13,188 | 17,946 |
| Total electric resource costs | 379,058 | 425,373 |
| Natural gas resource costs: | | |
| Natural gas purchased | 389,034 | 579,248 |
| Natural gas cost amortizations, net | 20,256 | 20,372 |
| Other regulatory amortizations, net | 11,191 | 6,996 |
| Total natural gas resource costs | 420,481 | 606,616 |
| Total resource costs | $ 799,539 | $ 1,031,989 |

Power purchased decreased $0.2 million due to a decrease in wholesale prices (decreased costs $35.4 million) offset by an increase in the volume of power purchases (increased costs $35.2 million), primarily due to purchasing power to cover for the outage at Colstrip and an increase in sales volumes related to optimization.

Net amortization of deferred power costs was $31.1 million for 2009 compared to $25.5 million for 2008. During 2009, we recovered (collected as revenue) $31.6 million of previously deferred power costs in Washington and $17.5 million in Idaho. During 2009, we deferred $18.0 million of power costs in Idaho, as power supply costs exceeded the amount included in base retail rates. We did not defer any power costs in Washington during 2009, as power supply costs were within the $4.0 million deadband below the amount included in base retail rates under the ERM.

Fuel for generation decreased $44.8 million due to a decrease in natural gas fuel prices, as well as a decrease in thermal generation (primarily due to the outage at Colstrip).

Other fuel costs decreased $11.2 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 increase in other regulatory amortizations of $9.1 million primarily relates to the amortization of costs under demand side management programs.

The expense for natural gas purchased decreased $190.2 million due to a decrease in the price of natural gas (decreased costs $214.7 million), partially offset by an increase in the total therms purchased (increased costs $24.5 million). The increase in total therms purchased was due to an increase in wholesale sales with the balancing of loads and resources as part of the natural gas procurement process, partially offset by a decrease in retail sales volumes. During 2009, we amortized $20.3 million of deferred natural gas costs compared to $20.4 million for 2008.

## ADVANTAGE IQ

### 2010 compared to 2009

Advantage IQ'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, Advantage IQ had 534 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, Advantage IQ managed bills totaling $17.3 billion, a decrease of $0.1 billion, or 0.8 percent, as compared to 2009. This decrease was primarily due to a decrease in the average value of each bill processed.

**2009 compared to 2008**

Advantage IQ's net income attributable to Avista Corporation was $5.3 million for 2009 compared to $6.1 million for 2008. Operating revenues increased $18.2 million and operating expenses increased $17.9 million. The increase in operating revenues and expenses was primarily due to the third quarter 2008 acquisition of Cadence Network and the third quarter 2009 acquisition of Ecos, as well as increased revenues from other customer billing services. These increases in operating revenues were partially offset by a decrease in interest revenue on funds held for customers (due to a decrease in interest rates). The increase in operating expenses was also due to the amortization of intangible assets from the acquisitions. As of December 31, 2009, Advantage IQ had 532 customers representing 421,000 billed sites in North America. In 2009, Advantage IQ managed bills totaling $17.4 billion, an increase of $0.7 billion, or 4 percent, as compared to 2008. The acquisition of Cadence Network added $1.7 billion in processed bills for 2009 as compared to 2008.

## OTHER BUSINESSES

**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. The loss for 2010 includes a $2.2 million impairment of our investment in a fuel cell business that was previously a subsidiary of the Company. In 2009, we recorded an impairment of a commercial building of $3.0 million.

**2009 compared to 2008**

The net loss attributable to Avista Corporation from these operations was $5.0 million for 2009 compared to $2.5 million for 2008. Operating revenues decreased $4.9 million and operating expenses increased $0.8 million. The decrease in operating revenues was primarily due to a reduction in sales at METALfx. The increase in operating expenses reflects the impairment of a commercial building of $3.0 million and increased litigation costs related to the remaining contracts and previous operations of Avista Energy, partially offset by decreased operating costs from METALfx. Losses on long-term venture fund investments were $0.8 million in 2009 compared to $1.4 million in 2008. METALfx had net income of $0.2 million for 2009 compared to $0.5 million for 2008.

## ACCOUNTING STANDARDS TO BE ADOPTED IN 2011

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 2011. For information on accounting standards adopted in 2010 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 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.

**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 $21.3 million for 2010, $25.8 million for 2009 and $13.9 million for 2008. 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.

In 2009, the Company reviewed the mortality table utilized in the actuarial calculations. The Company determined that the RP-2000 combined healthy mortality tables for males and females should be replaced with the RP-2000 combined healthy mortality tables for males and females projected to 2010 using scale AA. The change resulted in an increase of $6.6 million to the pension benefit obligation as of December 31, 2009.

We have not made any changes to pension plan provisions in 2010, 2009 and 2008 that have had any significant effect on our recorded pension plan amounts. We have revised the key assumption of the discount rate in 2010, 2009 and 2008. Such changes had an effect on our pension costs in 2010, 2009 and 2008 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 2010, we decreased the pension plan discount rate to 5.70 percent from 6.30 percent in 2009. We used a discount rate of 6.25 percent in 2008.

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 7.75 percent in 2010, a decrease from 8.5 percent used in 2009 and 2008. This increased pension costs in 2010 by approximately $2.0 million. The actual return on plan assets, net of fees, was a gain of $30.1 million (or 10.9 percent) for 2010, a gain of $50.1 million (or 24.4 percent) for 2009 and a loss of $63.2 million (or -25.5 percent) for 2008. 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% | $ —* | $ 1,379 |
| Expected long-term return on plan assets | +0.5% | —* | (1,379) |
| Discount rate | -0.5% | 28,878 | 2,450 |
| Discount rate | +0.5% | (25,904) | (2,226) |

** 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, 2010 by $5.2 million and the service and interest cost by $0.3 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, 2010 by $4.4 million and the service and interest cost by $0.2 million.

### Stock-Based Compensation

We recognize compensation costs relating to share-based payment transactions in our Consolidated Statements of Income based on the fair value of the equity or liability instruments issued. The fair value of each performance share award was estimated on the date of grant using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to a peer group. Expected volatility is based on the historical volatility of our common stock over a three-year period. The expected term of the performance shares is three years based on the performance cycle. The risk-free interest rate is based on the U.S. Treasury yield at the time of grant.

### 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.

## LIQUIDITY AND CAPITAL RESOURCES

### REVIEW OF CASH FLOW STATEMENT

**Overall** — During 2010, positive cash flows from operating activities of $228.4 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $202.2 million and dividends of $55.7 million. In December 2010, we issued $137.0 million of long-term debt. The net proceeds of $136.4 million from the issuance were used to redeem $75.0 million of long-term debt (plus a redemption premium of $10.7 million) and repay borrowings outstanding on our committed line of credit.

**Operating Activities** — Net cash provided by operating activities was $228.4 million for 2010 compared to $258.8 million for 2009. Net cash used in working capital components was $20.8 million for 2010, compared to net cash provided of $31.0 million for 2009. The net cash used during 2010 primarily reflects negative cash flows from:

- accounts receivable (representing an increase in receivables outstanding at Avista Utilities and Advantage IQ), 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.

The net cash provided during 2009 primarily reflects an increase in cash flows from:

- accounts receivable (representing a decrease in the receivables outstanding largely due to a decrease in wholesale prices, partially offset by a $17.0 million decrease in the amount of receivables that were sold),
- other current liabilities, and
- materials and supplies, fuel stock and natural gas stored (primarily reflecting a change in the price of natural gas stored).

This cash provided was partially offset by negative cash flows from accounts payable (primarily related to a decrease in the accounts payable for natural gas purchases due to a decrease in prices).

Significant non-cash items included $9.8 million of power and natural gas cost net deferrals for 2010, a change from net amortization of $51.4 million for 2009. We also had deferred income tax expense of $37.7 million for 2010 compared to $13.9 million for 2009.

Contributions to our defined benefit pension plan were $21.0 million for 2010 compared to $48.0 million for 2009. Income tax payments were $14.2 million in 2010, a decrease compared to $22.7 million for 2009. Cash paid for interest increased to $74.2 million for 2010, compared to $58.5 million for 2009.

**Investing Activities** — Net cash used in investing activities was $253.2 million for 2010, an increase compared to $210.2 million for 2009. Utility property capital expenditures decreased slightly for 2010 as compared to 2009, and funds held from customers at Advantage IQ increased by $48.9 million (compared to a decrease of $8.5 million for 2009). Typically, funds held from customers represents one day of deposits from customers, which are disbursed the following business day. As December 31, 2010 was a business holiday, Advantage IQ was holding two days of deposits from customers at the end of 2010.

**Financing Activities** — Net cash provided by financing activities was $57.2 million for 2010 compared to net cash used of $35.9 million for 2009. 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. Cash dividends paid increased to $55.7 million (or $1.00 per share) for 2010 from $44.4 million (or 81 cents per share) for 2009. We issued $46.2 million of common stock during 2010, including $43.2 million under a sales agency agreement. Additionally, customer funds obligations at Advantage IQ increased by $48.9 million (see explanation under "Investing Activities"). 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.

In September 2009, we issued $250.0 million (net proceeds of $249.4 million) of long-term debt. In conjunction with the issuance of long-term debt, we cash settled interest rate swap agreements and received a total of $10.8 million. In April 2009, we redeemed $61.9 million of long-term debt to affiliated trusts. In December 2009, we purchased $17.0 million of our Pollution Control Bonds, which we are holding as bondholder. During 2009, our short-term borrowings decreased $159.5 million. Additionally, customer funds obligations at Advantage IQ decreased by $8.5 million.

### 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 optimize capital expenditures, 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 capital markets in order to fund these needs as well as fund maturing debt. See further discussion at "Capital Resources."

We periodically file for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to move our earned returns closer to those 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 higher energy commodity prices and other increased operating costs through our new $400.0 million committed line of credit.

As of December 31, 2010, we had a combined $257.9 million of available liquidity under our committed lines of credit. As we have secured a new $400.0 million credit facility with an expiration date of February 2015, 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 will increase, which will negatively affect our cash flow and liquidity until such 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. Adverse 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, 2010, that we would potentially be required to post additional collateral up to $163 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 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, 2010, we had two interest rate swap agreements outstanding with a notional amount totaling $50 million and a mandatory cash settlement date of July 2012. We have not posted any collateral under these interest rate swap agreements.

## DODD-FRANK WALL STREET REFORM AND CONSUMER PROTECTION ACT

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was signed into law by President Obama on July 21, 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 otherwise would have been exempted under the Commodity Exchange Dodd-Frank Act, federal securities laws and federal banking laws.

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, which will be developed and implemented over timeframes as defined in the Dodd-Frank Act, could have a significant impact on Avista Corp. that was not clearly defined in the Act itself.

Under the Dodd-Frank Act, "Swap Dealers" and "Major Swap Participants" will be required to post collateral to meet minimum capital requirements as well as minimum initial and variation margin requirements, the purpose of which is to ensure the safety and soundness of the capital markets by addressing concerns brought about by the global financial crisis of 2007 and 2008. Swap Dealers and/or Major Swap Participants are persons who serve as dealers in swaps or who maintain a substantial position in swaps, for reasons other than mitigating commercial risk.

The Dodd-Frank Act also requires a broad category of swaps to be cleared and traded on registered exchanges or special derivatives exchanges. Such clearing requirements would result in a significant change from our current practice of bilateral transactions and negotiated credit terms. An exemption to such clearing requirements is outlined in the Dodd-Frank Act for end users that are not Major Swap Participants or Swap Dealers and enter into hedges to mitigate commercial risk. We expect to qualify under the end user exemption; however, concern remains that counterparties that are Swap Dealers or Major Swap Participants will pass along the increased cost and margin requirements through higher prices and reductions in unsecured credit limits.

We will continue to monitor developments and 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, 2010 and December 31, 2009 (dollars in thousands):**

| | December 31, 2010 | | December 31, 2009 | |
|---|---|---|---|---|
| | Amount | Percent of total | Amount | Percent of total |
| Current portion of long-term debt | $ 358 | —% | $ 35,189 | 1.5% |
| Current portion of nonrecourse long-term debt[1] | 12,463 | 0.5 | — | — |
| Short-term borrowings | 110,000 | 4.5 | 92,700 | 4.1 |
| Long-term debt to affiliated trusts | 51,547 | 2.1 | 51,547 | 2.3 |
| Nonrecourse long-term debt[1] | 46,471 | 1.9 | — | — |
| Long-term debt | 1,101,499 | 45.0 | 1,036,149 | 45.7 |
| Total debt | 1,322,338 | 54.0 | 1,215,585 | 53.6 |
| Total Avista Corporation stockholders' equity | 1,125,784 | 46.0 | 1,051,287 | 46.4 |
| Total | $ 2,448,122 | 100.0% | $ 2,266,872 | 100.0% |

*(1) Nonrecourse long-term debt (including current portion) represents the long-term debt of Spokane Energy, which was consolidated effective January 1, 2010. To provide funding to acquire a long-term fixed rate electric capacity contract from Avista Corp., Spokane Energy borrowed $145.0 million from a funding trust in December 1998. The long-term debt has scheduled monthly installments and interest at a fixed rate of 8.45 percent with the final payment due in January 2015. Spokane Energy bears full recourse risk for the debt, which is secured by the electric capacity contract and $1.6 million of funds held in a trust account.*

We need to finance capital expenditures and obtain additional working capital 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, working capital, purchased power, fuel and natural gas costs, dividends and other requirements. Our stockholders' equity increased $74.5 million during 2010 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 is expected to be the primary source of funds for operating needs, dividends and capital expenditures for 2011. Borrowings under our new $400.0 million committed line of credit will supplement these funds to the extent necessary.

We are planning to issue up to $25 million of common stock in 2011 in order to maintain our capital structure at an appropriate level for our business. We are party to a sales agency agreement under which we sell shares of our common stock from time to time. In 2010 we sold a total of 2.1 million shares for a total of $43.2 million. As of December 31, 2010, we had 1.0 million shares available to be issued under this agreement.

At December 31, 2010, we had a committed line of credit in the total amount of $320.0 million with an expiration date of April 2011. Additionally, at December 31, 2010, we had a committed line of credit in the total amount of $75.0 million with an expiration date of April 2011.

In February 2011, we entered into a new committed line of credit 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.

Our committed line of credit agreements contain customary covenants and default provisions. The $320.0 million and $75.0 million credit agreements had a covenant that required the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2010, we were in compliance with this covenant with a ratio of 4.13 to 1. The new $400.0 million committed line of credit does not have this covenant. The $320.0 million and $75.0 million committed line of credit agreements had a covenant which did not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 70 percent at any time. As of December 31, 2010, we were in compliance with this covenant with a ratio of 54.0 percent. Under the new $400.0 million committed line of credit, this ratio must not be greater than 65 percent at any time.

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Balance outstanding at end of period | $ 110,000 | $ 87,000 | $ 250,000 |
| Letters of credit outstanding at end of period | $ 27,126 | $ 28,448 | $ 24,325 |
| Maximum balance outstanding during the period | $ 170,000 | $ 275,000 | $ 250,000 |
| Average balance outstanding during the period | $ 80,230 | $ 186,474 | $ 48,426 |
| Average interest rate during the period | 0.60% | 0.65% | 3.04% |
| Average interest rate at end of period | 0.57% | 0.59% | 0.81% |

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, 2010, Avista Corp. and its subsidiaries were in compliance with all of the covenants of their financing agreements.

We are restricted under our Restated Articles of Incorporation as to the additional preferred stock we can issue. As of December 31, 2010, we could issue $724.9 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:

- 70 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, 2010, our property additions and retired bonds would have allowed us to issue $795.3 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2010, the net earnings test would limit the principal amount of additional bonds we could issue to $758.8 million. 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 $626.9 million for the years 2008 through 2010. We expect utility capital expenditures to be $250 million for 2011, and between $230 million and $240 million for each of 2012 and 2013. The increase in capital expenditures from $202.2 million in 2010 to $250 million in 2011 is primarily due to hydroelectric generation plant upgrades, smart grid projects and a slight increase in customer growth.

**Our capital budget for 2011 includes the following (dollars in millions):**

| | |
|---|---|
| Transmission and distribution | $ 68 |
| Generation | 42 |
| Customer growth | 40 |
| Information technology | 28 |
| Smart grid | 19 |
| Natural gas | 16 |
| Environmental | 12 |
| Other | 25 |
| Total | $ 250 |

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.

We applied to the Smart Grid Investment Grant program under the American Recovery and Reinvestment Act (the ARRA) of 2009, proposing a 50 percent cost share for the deployment of smart grid enabling technologies in the Spokane area. In October 2009, we were selected to negotiate a grant under this stimulus program. The grant is for $20 million and our contribution will be $22 million, the majority of which will be spent over a three-year period. We finalized the grant agreement with the Department of Energy in March 2010.

We applied with Battelle Northwest to participate in a Smart Grid Demonstration Project in Pullman, Washington under the ARRA. In November 2009, this project was selected by the Department of Energy for a grant. The funding agreement was finalized in September 2010. The Smart Grid Demonstration Project will partner with other regional utilities and proposes a 50 percent cost share for a group of projects. Our portion of the regional demonstration project is estimated to cost $15 million, the majority of which will be spent over a three-year period.

In February 2011, we issued a request for proposals (RFP) seeking to acquire up to 35 aMW of renewable energy, or as much as 100 MW of nameplate wind capacity with deliveries beginning in 2012. We completed the acquisition of the development rights for a wind generation site in 2008. While this RFP does not include the development of this site, we will continue to study this site in preparation for later development.

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."

We are continuing our participation in planning activities for the development of a proposed 1,000-3,000 MW transmission project that would extend from British Columbia, Canada to Northern California. The project would be implemented in two sections; one from Canada to northeastern Oregon (the northern section) and then on into California (the southern section). Western Area Power Administration is leading the development on the southern section and is working with Pacific Gas and Electric, Transmission Agency of Northern California and others. British Columbia Transmission Corporation is leading the development effort on the northern section. The participants have received a Western Electricity Coordinating Council (WECC) Phase I Rating for both sections of the project, and Avista Corp. is working on a WECC Phase II Rating for an interconnection from the project to the Avista Corp. transmission system. We have contributed $0.7 million to the project to date with no additional funding anticipated in 2011.

## ADVANTAGE IQ CREDIT AGREEMENT

As of December 31, 2010, Advantage IQ had a $15.0 million committed credit agreement with an expiration date of February 2011 that had no borrowings outstanding. Advantage IQ may elect to increase the credit facility to $25.0 million under the same agreement. The credit agreement is secured by substantially all of Advantage IQ's assets. In February 2011, Advantage IQ extended the expiration date of this credit agreement to May 2011. Advantage IQ is in the process of evaluating alternatives and expects to have a new credit facility in place prior to the May 2011 expiration of its current credit agreement.

## ADVANTAGE IQ REDEEMABLE STOCK

In 2007, Advantage IQ amended its employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Advantage IQ 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 $8.6 million as of December 31, 2010 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock. In 2009, the Advantage IQ 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 $38.1 million related to the Cadence Network acquisition, as the previous owners can exercise a right to put their stock back to Advantage IQ in July 2011 or July 2012 if Advantage IQ is not liquidated through either an initial public offering or sale of the business to a third party. Their redemption rights expire July 31, 2012. Should the previous owners of Cadence Network exercise their redemption rights, Advantage IQ 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, the other owners of Advantage IQ (including Avista Capital) purchased shares held by the one of the previous owners of Cadence Network (that owned 4.5 percent of Advantage IQ). Avista Capital's portion of the purchase was $5.6 million.

## ACCOUNTS RECEIVABLE FINANCING FACILITY

On December 30, 2010, Avista Corp., Avista Receivables Corporation (ARC), Bank of America, N.A. and Ranger Funding Company, LLC terminated a Receivables Purchase Agreement at the direction of the Company. ARC is a wholly owned, bankruptcy-remote subsidiary of the Company formed in 1997 for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. We elected to terminate the Receivables Purchase Agreement prior to its March 11, 2011 expiration date based on our forecasted liquidity needs. The Receivables Purchase Agreement was originally entered into on May 29, 2002 (and was renewed on an annual basis) and provided us with funds for general corporate needs. Under the Receivables Purchase Agreement, we could borrow up to $50.0 million based on calculations of eligible receivables. We did not borrow any funds under this revolving agreement in 2010.

## OFF-BALANCE SHEET ARRANGEMENTS

As of December 31, 2010, we had $27.1 million in letters of credit outstanding under our $320.0 million committed line of credit, a decrease from $28.4 million as of December 31, 2009.

## PENSION PLAN

As of December 31, 2010, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. In 2009 and 2010, the fair value of pension plan assets increased due to market returns and our contributions, offset by benefit payments. We contributed $21 million to the pension plan in 2010. We expect to contribute $26 million to the pension plan in 2011. 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 25, 2011:**

| | Standard & Poor's (1) | Moody's (2) |
|---|---|---|
| Avista Corporation | | |
| Corporate/Issuer rating | BBB- | Baa3 |
| Senior secured debt | BBB+ | Baa1 |
| Senior unsecured debt | N/A (3) | Baa3 |
| Rating outlook | Positive | Positive (4) |

*(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.*

*(3) Standard & Poor's has not assigned a rating to our senior unsecured debt. We do not have any senior unsecured debt outstanding.*

*(4) In February 2011, Moody's placed the ratings for Avista Corporation on review for possible upgrade.*

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 2011, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.275 per share on the Company's common stock. This was an increase of $0.025 per share, or 10 percent from the previous quarterly dividend of $0.25 per share.

## CONTRACTUAL OBLIGATIONS

**The following table provides a summary of our future contractual obligations as of December 31, 2010 (dollars in millions):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|
| Avista Utilities: | | | | | | |
| Long-term debt maturities | $ — | $ 7 | $ 50 | $ — | $ — | $ 1,042 |
| Long-term debt to affiliated trusts | — | — | — | — | — | 52 |
| Interest payments on long-term debt[1] | 61 | 61 | 60 | 60 | 60 | 611 |
| Short-term borrowings | 110 | — | — | — | — | — |
| Energy purchase contracts[2] | 356 | 260 | 203 | 171 | 154 | 1,299 |
| Public Utility District contracts[2] | 3 | 3 | 3 | 3 | 2 | 28 |
| Operating lease obligations[3] | 1 | 1 | 1 | 1 | — | 2 |
| Other obligations[4] | 22 | 23 | 23 | 23 | 25 | 252 |
| Information services contracts | 13 | 12 | 9 | 8 | 7 | 14 |
| Pension plan funding[5] | 26 | 30 | 33 | 28 | 21 | — |
| Spokane Energy: | | | | | | |
| Nonrecourse long-term debt maturities | 12 | 14 | 15 | 16 | 1 | — |
| Interest payments on nonrecourse long-term debt | 5 | 3 | 2 | 1 | — | — |
| Avista Capital (consolidated): | | | | | | |
| Redeemable noncontrolling interests[6] | 47 | — | — | — | — | — |
| Venture funds investments[7] | 2 | 2 | — | — | — | — |
| Operating lease obligations[3] | 3 | 3 | 3 | 3 | 1 | 4 |
| Total contractual obligations | $ 661 | $ 419 | $ 402 | $ 314 | $ 271 | $ 3,304 |

*(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, 2010.*

*(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.*

*(6) Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Advantage IQ common stock redeemed by Advantage IQ during July 2011 or July 2012 if Advantage IQ is not liquidated through either an initial public offering or sale of the business to a third party. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Advantage IQ at the time of the redemption election as determined by certain independent parties. In addition, certain shares acquired under Advantage IQ'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 set 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. 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.

Advantage IQ 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 Advantage IQ to be the first to market a new product or service to gain an advantage in market share. Other challenges for Advantage IQ include the availability of funding and resources to meet capital needs, and rapidly advancing technologies which requires continual product enhancement to avoid obsolescence.

## ECONOMIC CONDITIONS AND UTILITY LOAD GROWTH

The general economic data, on both national and local levels, contained in this section are 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 dramatically in the last couple of years. However, we have experienced customer growth, although this growth is less than we had been experiencing in recent years prior to the economic downturn. Employment improved slightly in most of our service area in 2010 after enduring significant cutbacks in the construction, forest products, mining and manufacturing sectors. Non-farm employment growth for 2010 was 0.4 percent in Coeur d'Alene, Idaho and Medford, Oregon. It was flat in the Spokane area but with positives in the retail trade and health sectors, offset by weakness in state and local government jobs. U.S. nonfarm sector jobs grew by 0.2 percent in the same period. Unemployment rates declined in December 2010 from the year earlier levels in Spokane and Medford, but rose in Coeur d'Alene. The Spokane rate declined from 9.3 percent to 9.2 percent from December 2009 to December 2010 and Medford from 11.6 percent to 11.5 percent while Coeur d'Alene rose from 10.8 percent to 11.3 percent. The U.S. rate declined from 9.7 percent to 9.1 percent in the same period. Although showing modest improvement during 2010, the housing markets in Coeur d'Alene and Medford have higher foreclosure rates than the national average. The December 2010 national rate was 0.20 percent with 0.37 percent in Kootenai County, Idaho and 0.23 percent in Jackson County, Oregon. The Spokane housing market had a foreclosure rate of 0.10 percent.

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 2011-2014. We anticipate customer and load growth at the lower end of the range in 2011 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.

We monitor legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to alter 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, 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 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 the streamflows, which impacts 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. 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 per year. As the U.S. Congress did not enact any comprehensive climate change legislation in 2010, for the foreseeable future climate change regulations are expected to emerge from the EPA and individual states.

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 wind contracts) 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.

We have a Climate Council (an interdisciplinary team of management and other employees) which is designed to:

- anticipate and evaluate strategic needs and opportunities relating to climate change,
- analyze the company-wide implications of various trends and proposals,
- develop recommendations on positions and action plans, and
- facilitate internal and external communications regarding climate change issues.

Longer-term issues followed by the Climate Council include: state and federal emissions tracking and certification, recommendations for GHG reduction goals and activities, the merits of different reduction programs, the development of legislation, and climate change policies and activities adopted by other organizations.

**National Legislation**

Climate change legislation has been proposed in the U.S. Congress; however, recent actions in the U.S. Senate and the outcome of the mid-term (November 2010) elections strongly indicate that climate change legislation is unlikely until 2013 or later. We continue to monitor the situation for new developments that could affect our business.

**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). The EPA found that the current and projected concentrations of the six key well-mixed greenhouse gases — carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride — in the atmosphere threaten the public health and welfare of current and future generations. The EPA also found that the combined emissions of these well-mixed greenhouse gases 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. The EPA's final decision has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit. In September 2009, the EPA proposed a rule that would establish an applicability threshold for regulating GHG 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 large stationary sources begin to address GHG emissions, as well as require Best Available Control Technology (BACT) to control these emissions. On January 12, 2011, the EPA waived GHG permits for the next three years for utilities, boilers and other industrial facilities using biomass. The EPA also announced a schedule for issuing regulations controlling GHG emissions from electric generating units. According to this schedule, the EPA will propose standards for natural gas, oil and coal-fired electric generating units by July 26, 2011, and issue final standards by May 26, 2012. The EPA agreed to this schedule as part of a settlement with several states, local governments and environmental organizations that had 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 NSPS that set emissions limits for new facilities and address emissions from existing facilities. These rules could impact the costs of significantly 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 a rule that requires facilities emitting over 25,000 metric tons of greenhouse GHG a year to report their emissions to the EPA beginning in January 2011 for 2010 emissions. The rule became effective on December 29, 2009. Data collection commenced January 1, 2010 and we will submit our first GHG emissions report to the EPA by March 31, 2011 for covered facilities. Based on rule applicability criteria, Colstrip, Coyote Springs 2, and the Rathdrum CT will be required to report GHGs. These facilities currently report carbon dioxide to the EPA under the Acid Rain Program and it is expected that the operators of Colstrip and Coyote Springs 2 will be responsible for any additional GHG reporting. Based on our evaluation of historical emissions from 2004-2008, none of our other electrical generation facilities meet the threshold requirements. The rule also requires that natural gas distribution system throughput be reported. Monitoring methods, per the rule, are currently in place and development of a GHG Monitoring Plan for covered facilities was in place prior to the April 1, 2010 deadline for required monitoring method implementation. The purpose of the plan is to document the process and procedures for collecting and reviewing the data needed to estimate annual GHG emissions. On March 22, 2010, the EPA proposed to amend its reporting rule to include several new source categories, including reporting of GHG emissions from electric power transmission and distribution systems. On May 13, 2010, the EPA issued a final rule on GHG emissions reporting for stationary sources. As stated above, Colstrip, Coyote Springs 2 and the Rathdrum CT will be required to report GHG emissions, even under modified rule. We continue to monitor developments.

**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.

Washington and Oregon continue to participate in the Western Climate Initiative (WCI), along with the states of Arizona, California, New Mexico, Utah and Montana, and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. The WCI has adopted a regional cap-and-trade program with an overall regional goal for reducing GHG emissions to 15 percent below 2005 levels by 2020. The WCI's program design includes cap-and-trade regulation of the electricity sector in 2012 and of emissions associated with the distribution of natural gas by 2015. Neither Washington, nor Oregon has enacted legislation establishing the WCI's program requirements. The only members of the WCI from the U.S. that are prepared to participate in the WCI's regional cap-and-trade system are California and New Mexico. A central element of the WCI's cap and trade design is a requirement that its members regulate GHG emissions from sources of electricity that serve loads within their respective jurisdictions, even though those sources may be located beyond their boundaries.

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 deemed a "facility" for the purposes of potentially regulating emissions associated with the importation of power to serve our Washington loads under cap-and-trade or other forms of regulation. The state of Washington has yet to identify how it might impose and enforce emission reductions since the legislature failed to enact a bill in 2009 that would have authorized the Department of Ecology to implement cap-and-trade policies. The state's Department of Ecology is proceeding to adopt regulations to ensure that Washington's 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 Clean Air Act authorities.

Washington and Oregon apply a GHG emissions performance standard to electric generation facilities used to serve loads in their jurisdiction. 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 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 will result in penalties of at least $50 per MWh 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.

**Electric Integrated Resource Plan**

Our most recent Electric Integrated Resource Plan (IRP), which we filed with the WUTC and the IPUC in the third quarter 2009, includes the acquisition of additional renewable resources such that, if the Preferred Resources Strategy is implemented, we would be compliant with the requirements of I-937 by the various milestone dates. Highlights of the 2009 IRP include:

- Up to 150 MW of wind power by 2012,
- An additional 200 MW of wind power by 2022,
- 750 MW of natural gas-fired generation facilities,
- Aggressive energy efficiency measures to reduce new generation requirements by 26 percent or 339 MW,
- Transmission upgrades are needed to integrate new generation resources into our system, and
- Hydroelectric upgrades at existing facilities will generate additional renewable energy.

We are required to file an IRP every two years. We will file an IRP in August 2011 and our resource strategy may change from the highlights included above based upon market, legislative and regulatory developments.

In February 2011, we issued a RFP seeking to acquire up to 35 aMW of renewable energy, or as much as 100 MW of nameplate wind capacity with deliveries beginning in 2012. We have issued this RFP due to recent market changes, tax incentives that remain in effect and a recent WUTC policy statement indicating support of the acquisition of renewable resources in advance of renewable portfolio standards deadlines, if early acquisition can be cost-justified. We completed the acquisition of the development rights for a wind generation site in 2008. While this RFP does not include the development of this site, we will continue to study this 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 and the purchase of a small amount of renewable energy credits from 2012 through 2015. The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes or if a federal renewable energy standard were passed.

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 of warming every 25 years. Incorporating the warming trend finds that in 20 years summer load would be approximately 26 aMW higher than the 30-year average. In the winter, loads would be approximately 40 aMW lower in 2029, for a net impact of a 14 aMW load decrease. Our projected system load for 2010 in the IRP was 1,101 aMW. We do not expect this trend to have a material impact on our results of operations. Estimated costs of GHG emission credits were also included in the development of the IRP market prices.

**Chicago Climate Exchange**

In October 2007, we became a member of the Chicago Climate Exchange (CCX). Members agreed to reduce their GHG emissions by 6 percent from an established baseline by 2010. The CCX allowed participants who exceeded their reduction targets to bank or sell the excess CCX Carbon Financial Instruments. We liquidated our 2007 surplus credits in June and July 2009. The audit establishing our 2008 baseline emissions was completed and we received 1,519 of 2008 vintage CCX Carbon Financial Instruments in September 2009. The 2009 emissions audit data was submitted in the second quarter of 2010 and we received 1,623 of 2009 vintage CCX Carbon Financial Instruments in October 2010. In October 2010, the CCX announced that they will not be offering a Phase 3 program. As such, we concluded our participation in the CCX in 2010.

**Clean Air Act**

We must comply with requirements under the CAA and Clean Air Act Amendments (CAAA) in operating our thermal generating plants. The most significant impacts on us, related to the CAA and the 1990 CAAA, pertain to Colstrip, which is a "Phase II" coal-fired plant for sulfur dioxide ($SO_2$) under the CAAA. However, we do not expect Colstrip to be required to implement any additional $SO_2$ mitigation in the foreseeable future in order to continue operations. Our other thermal projects are subject to various CAAA standards. Every five years each of the other thermal projects requires an updated operating permit (known as a Title V permit), which addresses, among other things, the compliance of the plant with the CAAA. The operating permit for the Rathdrum CT was renewed in 2006 (expires in 2011) and the operating permit for the Kettle Falls GS was renewed in 2007 (expires in 2012). Coyote Springs 2 was issued a renewed Title V permit in 2008 that expires in 2013. Boulder Park and the Northeast CT do not require a Title V permit based on their limited output and instead each has a synthetic minor permit that does not expire.

**Mercury Emissions**

In 2006, the Montana Department of Environmental Quality (Montana DEQ) adopted final rules for the control of mercury emissions from coal-fired plants. The new rules set strict mercury emission limits by 2010, and establish a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities. The joint owners of Colstrip believe, based upon current results, that the plant will be able to comply with the Montana law without utilizing the temporary alternate emissions limit provision. In addition, the EPA has announced its intent to develop maximum achievable control technology standards to control hazardous air pollutants, including mercury, from coal-fired power plants that do not allow for trading of emission allowances. It is likely that the level of emissions required by the final rule will be based upon the average of the top 12 percent of the best performers in the industry. As a result, it is possible that the federal standard could be more stringent than the Montana DEQ rule.

**National Ambient Air Quality Standards**

We continue to monitor legislative and regulatory developments at both the state and national levels for potential further restrictions on National Ambient Air Quality Standards. New, more stringent ambient air quality standards were adopted or are being adopted by the EPA for nitrogen dioxide, ozone and particulate matter. We have thermal power plants in Washington, Idaho, Montana and Oregon. Even under the new standards, the EPA and the states have designated most of the western states in which we operate as attainment areas for the new standards. We do not anticipate any material impacts on our thermal plants from these new standards.

### Coal Ash Management/Disposal

Currently, coal combustion byproducts (CCBs) are not regulated by the EPA as a hazardous waste. The EPA is currently reconsidering the classification of CCBs under the Resource Conservation and Recovery Act (RCRA). A draft proposal is under review at the Office of Management and Budget, but no proposal regarding such regulation has been issued for public review or comment. 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. The EPA provided proposed draft rules in 2010 for public review and comment, with two alternatives. One would require management of CCBs as a hazardous waste under Subtitle C of RCRA; the other would regulate coal ash under Subtitle D, for solid wastes. Along with many other parties, Avista Corp. submitted comments supporting ongoing regulation of CCBs as a solid waste, with all applicable exclusions sustained. The EPA has not indicated any schedule for final rulemaking.

### 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. Thus far, measures that were adopted and implemented to save the Snake River sockeye salmon and fall chinook salmon have not directly impacted generation levels at any of our hydroelectric facilities. We purchase power under long-term contracts with certain PUDs 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, particularly bull trout, is a key part of the agreement. The result is a collaborative bull trout recovery 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. See "Hydroelectric Licensing" and "Fish Passage at Cabinet Gorge and Noxon Rapids" in "Note 24 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, 2010, 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 24 of the Notes to Consolidated Financial Statements" for further information on the refund proceedings.

### Other

For other environmental issues and other contingencies see "Note 24 of the Notes to Consolidated Financial Statements."

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### General

Our power supply cost varies because of several factors. We optimize the mix of power resources to meet our retail customer requirements and other obligations. We also use our resources and obtain resources from others in the wholesale power market (including natural gas fuel markets). Hydroelectric generation is typically the least cost source of supply, but the amount of hydroelectric generation depends on streamflow conditions (affected by both the volume and timing of precipitation, including snow melt patterns) and other factors in the watersheds for our hydroelectric facilities. Thermal generation resource costs vary with fuel costs and other factors. 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). Generating resource availability and regional demand tend to impact energy prices, which affect our net power supply costs.

Even with regulatory cost recovery mechanisms that address these power supply cost variations, a portion of the cost variation is not passed on to customers. In addition, the timing of incurring costs can be significantly different than the timing for recovering costs, resulting in the need for a significant liquidity cushion.

Our hydroelectric generation was below normal (based on a 70-year average) in 2010 and in nine of the past eleven years. We cannot determine if lower than normal hydroelectric generation will continue in future years. When we have excess hydroelectric generation, its value varies with market prices and other displaceable resources. When hydroelectric generation is below normal, the cost to obtain power from other sources is generally higher. When hydroelectric generation is above normal, prices in the wholesale market are often depressed which can adversely impact our surplus sales revenues. 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."

Market prices for natural gas continue to be competitive compared to alternative fuel sources for customers, and we believe that natural gas should sustain its long-term market advantage over competing energy sources based on the levels of existing reserves and potential natural gas development in the future. Growth has occurred in the natural gas business due to increased demand for natural gas in new construction and conversions from competing space and water heating energy sources to natural gas.

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.

**Commodity Price Risk**

In general, price risk is driven by fluctuation in the market price of the commodity needed, held or traded. The price of energy in wholesale markets is affected primarily by fundamental factors related to production costs and by other factors including weather and the resulting impact on retail loads. We hedge our exposure to price risk by making forward commitments for energy purchases and sales as further described under "Risk Management."

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 of 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 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.

We have mechanisms in each regulatory jurisdiction that provide for recovery of the majority of our power and natural gas costs. The majority of power and natural gas costs exceeding the amount currently recovered through retail rates, excluding the ERM deadband (and other sharing components) in Washington, are deferred on our Consolidated Balance Sheets for the opportunity for recovery through future retail rates. The recovery of these deferred power and natural gas costs is subject to review for prudence and, as such, certain deferred costs may be disallowed by the respective regulatory agencies.

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.

**The following table presents energy commodity derivative fair values as a net asset or (liability) as of December 31, 2010 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 |
| 2011 | $ (5,311) | $ (9,576) | $ (38,812) | $ 891 | $ 460 | $ 2,047 | $ 44 | $ 1,365 |
| 2012 | 567 | (4,997) | (12,811) | (1,266) | (114) | 238 | (1,948) | 535 |
| 2013 | 2,147 | — | (4,521) | (480) | (105) | — | (1,620) | (9) |
| 2014 | 2,132 | — | (203) | (271) | (160) | — | (1,718) | — |
| 2015 | 2,365 | — | 133 | — | (256) | — | — | — |
| Thereafter | 8,349 | — | — | — | (1,710) | — | — | — |

**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. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when we establish conservative credit limits. 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.

Should a counterparty, customer or supplier 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 clearing arrangements that essentially eliminate 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, defaults by our counterparties periodically occur.

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 unsettled net positions and future obligations by counterparties to pay us or deliver to us warrant.

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

- electric utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions, 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 the exposure that counterparties perceive related to our ability to perform deliveries and settlement under physical and financial energy contracts. These counterparties may seek assurances of performance in the form of letters of credit, prepayment or cash deposits from us.

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.

Credit risks related to our retail customer base include the extent to which customers do not pay or are slow to pay for energy we have delivered to them. We are allowed to recover normal credit losses in retail rates but economic conditions for our customers may result in unrecovered credit losses. We also extend credit (generally for up to five years) in certain circumstances to construction developers for the cost of utility infrastructure investment. The infrastructure costs are typically recovered when new customers begin receiving utility service but to the extent that customers do not connect as planned, we may carry credit risks with these developers.

We maintain credit reserves that are based on the evaluation of the credit risk of the overall portfolio. Based on our credit policies, exposures and credit reserves, we do not anticipate a materially adverse effect on our financial condition or results of operations as a result of counterparty nonperformance.

**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 and by monitoring the effects of market changes in interest rates. 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 enter into financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements to manage and mitigate interest rate risk exposure.

In the second quarter of 2010, we entered into two interest rate swap agreements with a total notional amount of $50.0 million and a mandatory cash settlement date of July 2012.

Under the terms of the outstanding interest rate swap agreements, the value of the interest rate swaps is determined based upon Avista Corp. paying a fixed rate and receiving a variable rate based on LIBOR for a term of ten years. As of December 31, 2010, we had a long-term derivative asset of $0.1 million and an offsetting regulatory liability, as well as a long-term derivative liability and an offsetting regulatory asset of less than $0.1 million 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, 2010 would decrease this derivative liability by $0.4 million, while a 10-basis-point decrease would increase the liability by $0.4 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 weighted average variable rate on outstanding short-term borrowings was 0.57 percent at December 31, 2010.

**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, 2010 (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter | Total | Fair Value |
|---|---|---|---|---|---|---|---|---|
| Fixed rate long-term debt | — | $ 7,000 | $ 50,000 | — | — | $ 1,042,100 | $ 1,099,100 | $ 1,139,765 |
| Weighted average interest rate | — | 7.37% | 1.68% | — | — | 5.66% | 5.49% | |
| Fixed rate nonrecourse long-term debt of Spokane Energy | $ 12,463 | $ 13,668 | $ 14,965 | $ 16,407 | $ 1,431 | — | $ 58,934 | $ 64,795 |
| Weighted average interest rate | 8.45% | 8.45% | 8.45% | 8.45% | 8.45% | — | 8.45% | |
| Variable rate long-term debt to affiliated trusts | — | — | — | — | — | $ 51,547 | $ 51,547 | $ 37,114 |
| Weighted average interest rate | — | — | — | — | — | 1.17% | 1.17% | |

**Foreign Currency Risk**

A significant portion of our utility natural gas supply (including fuel for electric generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of our short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within sixty days with U.S. dollars. We economically hedge a portion of the foreign currency risk by purchasing Canadian currency when such commodity transactions are initiated. This risk has not had a material effect on our financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations were included with natural gas supply costs for ratemaking. As of December 31, 2010, we had a current derivative asset for foreign currency hedges of $0.1 million included in other current assets on the Consolidated Balance Sheet. As of December 31, 2010, we had entered into 29 Canadian currency forward contracts with a notional amount of $10.9 million ($11.0 million Canadian).

**Risk Management**

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 risk assessment and risk management policies, including 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 and it monitors compliance with our risk management policy and control procedures. 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.

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 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. Effective January 1, 2010, the natural gas-fired Lancaster power purchase agreement was added to our utility resource portfolio, which increased the extent of transactions for natural gas fuel hedging and plant optimization.

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 36 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.

Further information for derivatives and fair values is disclosed at "Note 6 of the Notes to Consolidated Financial Statements" and "Note 20 of the Notes to Consolidated Financial Statements."

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of income, comprehensive income, equity and redeemable noncontrolling interests, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Avista Corporation and subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 2 to the consolidated financial statements, the Company has changed its method of accounting for variable interest entities effective January 1, 2010, due to the adoption of Accounting Standards Update No. 2009-17, *Consolidations — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2011, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 25, 2011

## CONSOLIDATED STATEMENTS OF INCOME

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Operating Revenues: | | | |
| Utility revenues | $ 1,417,846 | $ 1,395,201 | $ 1,572,664 |
| Non-utility energy marketing and trading revenues | 20,018 | 24,436 | 25,225 |
| Other non-utility revenues | 120,876 | 92,928 | 78,874 |
| Total operating revenues | 1,558,740 | 1,512,565 | 1,676,763 |
| Operating Expenses: | | | |
| Utility operating expenses: | | | |
| Resource costs | 795,075 | 799,539 | 1,031,989 |
| Other operating expenses | 242,521 | 229,907 | 206,528 |
| Depreciation and amortization | 100,554 | 93,783 | 87,845 |
| Taxes other than income taxes | 73,392 | 76,583 | 72,057 |
| Non-utility operating expenses: | | | |
| Resource costs | 11,389 | 23,408 | 23,553 |
| Other operating expenses | 98,549 | 82,695 | 65,093 |
| Depreciation and amortization | 7,072 | 5,992 | 4,787 |
| Total operating expenses | 1,328,552 | 1,311,907 | 1,491,852 |
| Income from operations | 230,188 | 200,658 | 184,911 |
| Interest expense | (75,789) | (65,077) | (73,446) |
| Interest expense to affiliated trusts | (635) | (1,957) | (6,141) |
| Capitalized interest | 298 | 545 | 4,612 |
| Other income (expense) — net | (7,957) | 802 | 10,446 |
| Income before income taxes | 146,105 | 134,971 | 120,382 |
| Income tax expense | 51,157 | 46,323 | 45,625 |
| Net income | 94,948 | 88,648 | 74,757 |
| Less: Net income attributable to noncontrolling interests | (2,523) | (1,577) | (1,137) |
| Net income attributable to Avista Corporation | $ 92,425 | $ 87,071 | $ 73,620 |
| Weighted-average common shares outstanding (thousands), basic | 55,595 | 54,694 | 53,637 |
| Weighted-average common shares outstanding (thousands), diluted | 55,824 | 54,942 | 54,028 |
| Earnings per common share attributable to Avista Corporation: | | | |
| Basic | $ 1.66 | $ 1.59 | $ 1.37 |
| Diluted | $ 1.65 | $ 1.58 | $ 1.36 |
| Dividends paid per common share | $ 1.00 | $ 0.81 | $ 0.69 |

*The Accompanying Notes are an Integral Part of These Statements.*

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

*Avista Corporation*
*For the Years Ended December 31,*
*Dollars in thousands*

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Net income | $ 94,948 | $ 88,648 | $ 74,757 |
| Other Comprehensive Income (Loss): | | | |
| Unrealized losses on interest rate swap agreements — net of taxes of $(2,063) | — | — | (3,831) |
| Reclassification adjustment for realized losses on interest rate swap agreements deferred as a regulatory asset (included in long-term debt) — net of taxes of $5,738 | — | — | 10,657 |
| Change in unfunded benefit obligation for pension plan — net of taxes of $(1,064), $2,015 and $3,602, respectively | (1,976) | 3,742 | 6,690 |
| Total other comprehensive income (loss) | (1,976) | 3,742 | 13,516 |
| Comprehensive income | 92,972 | 92,390 | 88,273 |
| Comprehensive income attributable to noncontrolling interests | (2,523) | (1,577) | (1,137) |
| Comprehensive income attributable to Avista Corporation | $ 90,449 | $ 90,813 | $ 87,136 |

*The Accompanying Notes are an Integral Part of These Statements.*

*Avista Corporation*
*As of December 31,*
*Dollars in thousands*

| | 2010 | 2009 |
|---|---|---|
| **Assets:** | | |
| Current Assets: | | |
| Cash and cash equivalents | $ 69,413 | $ 37,035 |
| Accounts and notes receivable-less allowances of $44,883 and $42,928 | 230,229 | 210,645 |
| Current portion of long-term energy contract receivable of Spokane Energy | 9,645 | — |
| Utility energy commodity derivative assets | 2,592 | 7,757 |
| Regulatory asset for utility derivatives | 48,891 | 8,330 |
| Funds held for customers | 100,543 | 51,648 |
| Materials and supplies, fuel stock and natural gas stored | 48,530 | 37,282 |
| Deferred income taxes | 28,822 | 34,473 |
| Income taxes receivable | 19,069 | 16,438 |
| Other current assets | 21,831 | 15,315 |
| Total current assets | 579,565 | 418,923 |
| Net Utility Property: | | |
| Utility plant in service | 3,713,885 | 3,549,658 |
| Construction work in progress | 62,051 | 60,055 |
| Total | 3,775,936 | 3,609,713 |
| Less: Accumulated depreciation and amortization | 1,061,699 | 1,002,702 |
| Total net utility property | 2,714,237 | 2,607,011 |
| Other Non-current Assets: | | |
| Investment in exchange power-net | 21,233 | 23,683 |
| Investment in affiliated trusts | 11,547 | 11,547 |
| Goodwill | 25,935 | 24,718 |
| Long-term energy contract receivable of Spokane Energy | 62,525 | — |
| Other property and investments-net | 74,553 | 77,590 |
| Total other non-current assets | 195,793 | 137,538 |
| Deferred Charges: | | |
| Regulatory assets for deferred income tax | 90,025 | 97,945 |
| Regulatory assets for pensions and other postretirement benefits | 178,985 | 141,085 |
| Other regulatory assets | 112,830 | 109,825 |
| Non-current utility energy commodity derivative assets | 15,261 | 45,483 |
| Non-current regulatory asset for utility derivatives | 15,724 | — |
| Power deferrals | 18,305 | 27,771 |
| Other deferred charges | 19,370 | 21,378 |
| Total deferred charges | 450,500 | 443,487 |
| Total assets | $ 3,940,095 | $ 3,606,959 |

*The Accompanying Notes are an Integral Part of These Statements.*

*Avista Corporation*
*As of December 31,*
*Dollars in thousands*

| | 2010 | 2009 |
|---|---|---|
| **Liabilities and Equity:** | | |
| Current Liabilities: | | |
| Accounts payable | $ 171,707 | $ 160,861 |
| Customer fund obligations | 100,543 | 51,648 |
| Current portion of long-term debt | 358 | 35,189 |
| Current portion of nonrecourse long-term debt of Spokane Energy | 12,463 | — |
| Short-term borrowings | 110,000 | 92,700 |
| Utility energy commodity derivative liabilities | 51,483 | 16,087 |
| Natural gas deferrals | 22,074 | 39,952 |
| Other current liabilities | 110,547 | 106,980 |
| Total current liabilities | 579,175 | 503,417 |
| Long-term debt | 1,101,499 | 1,036,149 |
| Nonrecourse long-term debt of Spokane Energy | 46,471 | — |
| Long-term debt to affiliated trusts | 51,547 | 51,547 |
| Regulatory liability for utility plant retirement costs | 223,131 | 217,176 |
| Non-current regulatory liability for utility derivatives | — | 42,611 |
| Pensions and other postretirement benefits | 161,189 | 123,281 |
| Deferred income taxes | 495,474 | 494,666 |
| Other non-current liabilities and deferred credits | 109,703 | 52,665 |
| Total liabilities | 2,768,189 | 2,521,512 |
| Commitments and Contingencies (See Notes to Consolidated Financial Statements) | | |
| Redeemable Noncontrolling Interests | 46,722 | 34,833 |
| Equity: | | |
| Avista Corporation Stockholders' Equity: | | |
| Common stock, no par value; 200,000,000 shares authorized; 57,119,723 and 54,836,781 shares outstanding | 827,592 | 778,647 |
| Accumulated other comprehensive loss | (4,326) | (2,350) |
| Retained earnings | 302,518 | 274,990 |
| Total Avista Corporation stockholders' equity | 1,125,784 | 1,051,287 |
| Noncontrolling Interests | (600) | (673) |
| Total equity | 1,125,184 | 1,050,614 |
| Total liabilities and equity | $ 3,940,095 | $ 3,606,959 |

*The Accompanying Notes are an Integral Part of These Statements.*

## CONSOLIDATED STATEMENTS OF CASH FLOWS

*Avista Corporation*
*For the Years Ended December 31,*
*Dollars in thousands*

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Operating Activities: | | | |
| Net income | $ 94,948 | $ 88,648 | $ 74,757 |
| Non-cash items included in net income: | | | |
| Depreciation and amortization | 107,626 | 99,775 | 92,632 |
| Provision for deferred income taxes | 37,734 | 13,853 | 44,161 |
| Power and natural gas cost amortizations (deferrals), net | (9,795) | 51,359 | 45,836 |
| Amortization of debt expense | 4,414 | 5,673 | 4,673 |
| Amortization of investment in exchange power | 2,450 | 2,450 | 2,450 |
| Stock-based compensation expense | 4,916 | 2,906 | 3,001 |
| Equity-related AFUDC | (3,353) | (3,078) | (5,692) |
| Other | 35,261 | 26,147 | 20,544 |
| Payments for settlements with Coeur d'Alene Tribe | (4,000) | (12,000) | (25,187) |
| Contributions to defined benefit pension plan | (21,000) | (48,000) | (28,000) |
| Changes in working capital components: | | | |
| Accounts and notes receivable | (19,081) | 14,659 | (116,714) |
| Materials and supplies, fuel stock and natural gas stored | (11,248) | 16,245 | (18,541) |
| Other current assets | (9,230) | (3,528) | (10,494) |
| Accounts payable | 13,606 | (18,444) | 47,669 |
| Deposits from counterparties | (2,000) | 3,000 | (12,290) |
| Other current liabilities | 7,189 | 19,116 | (3,427) |
| Net cash provided by operating activities | 228,437 | 258,781 | 115,378 |
| Investing Activities: | | | |
| Utility property capital expenditures (excluding equity-related AFUDC) | (202,227) | (205,384) | (219,239) |
| Other capital expenditures | (2,429) | (3,120) | (3,459) |
| Federal grant payments received | 7,585 | — | — |
| Decrease in restricted cash | — | — | 4,068 |
| Cash paid by subsidiary for acquisition, net of cash received | (3,777) | (8,572) | (1,440) |
| Decrease (increase) in funds held for customers | (48,895) | 8,507 | 30,790 |
| Proceeds from asset sales | 631 | 129 | 7,998 |
| Other | (4,111) | (1,712) | 2,561 |
| Net cash used in investing activities | (253,223) | (210,152) | (178,721) |

*The Accompanying Notes are an Integral Part of These Statements.*

## CONSOLIDATED STATEMENTS OF CASH FLOWS (CONTINUED)

*Avista Corporation*
*For the Years Ended December 31,*
*Dollars in thousands*

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Financing Activities: | | | |
| Net increase (decrease) in short-term borrowings | $ 23,000 | $ (159,500) | $ 252,200 |
| Borrowings from Advantage IQ line of credit | 2,300 | — | — |
| Repayment of borrowings from Advantage IQ line of credit | (8,000) | — | — |
| Proceeds from issuance of long-term debt | 136,365 | 249,425 | 296,165 |
| Redemption and maturity of long-term debt | (110,242) | (17,266) | (403,856) |
| Premiums paid for the redemption of long-term debt | (10,710) | — | — |
| Maturity of nonrecourse long-term debt of Spokane Energy | (11,370) | — | — |
| Redemption of long-term debt to affiliated trusts | — | (61,856) | — |
| Long-term debt and short-term borrowing issuance costs | (916) | (3,726) | (5,024) |
| Cash received (paid) in interest rate swap agreements | — | 10,776 | (16,395) |
| Issuance of common stock | 46,235 | 2,622 | 28,565 |
| Cash dividends paid | (55,682) | (44,360) | (37,071) |
| Purchase of subsidiary noncontrolling interest | (2,593) | (5,450) | (6,624) |
| Increase (decrease) in customer fund obligations | 48,895 | (8,507) | (30,790) |
| Other | (118) | 1,935 | (1,353) |
| Net cash provided by (used in) financing activities | 57,164 | (35,907) | 75,817 |
| Net increase in cash and cash equivalents | 32,378 | 12,722 | 12,474 |
| Cash and cash equivalents at beginning of year | 37,035 | 24,313 | 11,839 |
| Cash and cash equivalents at end of year | $ 69,413 | $ 37,035 | $ 24,313 |
| Supplemental Cash Flow Information: | | | |
| Cash paid during the year: | | | |
| Interest | $ 74,195 | $ 58,756 | $ 76,620 |
| Income taxes | 14,153 | 22,695 | 10,004 |
| Non-cash financing and investing activities: | | | |
| Accounts payable for capital expenditures | 8,315 | 8,404 | 10,509 |
| Utility property acquired under capital leases | 5,300 | — | — |
| Redeemable noncontrolling interests | 10,442 | (400) | 21,362 |
| Contingent consideration by subsidiary for acquisition | 1,134 | — | — |
| Issuance of stock by subsidiary for acquisition | — | — | 37,000 |

*The Accompanying Notes are an Integral Part of These Statements.*

## CONSOLIDATED STATEMENTS OF EQUITY AND REDEEMABLE NONCONTROLLING INTERESTS

*Avista Corporation*
*For the Years Ended December 31,*
*Dollars in thousands*

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Common Stock, Shares: | | | |
| Shares outstanding at beginning of year | 54,836,781 | 54,487,574 | 52,909,013 |
| Issuance of common stock through equity compensation plans | 141,645 | 343,498 | 697,257 |
| Issuance of common stock through Employee Investment Plan (401-K) | 11,116 | 4,309 | 15,361 |
| Issuance of common stock through Dividend Reinvestment Plan | 76,071 | 1,400 | 115,943 |
| Issuance of common stock | 2,054,110 | — | 750,000 |
| Shares outstanding at end of year | 57,119,723 | 54,836,781 | 54,487,574 |
| Common Stock, Amount: | | | |
| Balance at beginning of year | $ 778,647 | $ 774,986 | $ 726,933 |
| Equity compensation expense | 3,097 | 2,711 | 2,600 |
| Issuance of common stock through equity compensation plans | 1,942 | 2,666 | 9,326 |
| Issuance of common stock through Employee Investment Plan (401-K) | 235 | 71 | 311 |
| Issuance of common stock through Dividend Reinvestment Plan | 1,451 | 26 | 2,328 |
| Issuance of common stock, net of issuance costs | 42,607 | (141) | 16,599 |
| Equity transactions of consolidated subsidiaries | (387) | (1,672) | 16,889 |
| Balance at end of year | $ 827,592 | $ 778,647 | $ 774,986 |
| Accumulated Other Comprehensive Income (Loss): | | | |
| Balance at beginning of year | $ (2,350) | $ (6,092) | $ (19,608) |
| Other comprehensive income (loss) | (1,976) | 3,742 | 13,516 |
| Balance at end of year | $ (4,326) | $ (2,350) | $ (6,092) |
| Retained Earnings: | | | |
| Balance at beginning of year | $ 274,990 | $ 227,989 | $ 206,641 |
| Net income attributable to Avista Corporation | 92,425 | 87,071 | 73,620 |
| Cash dividends paid (common stock) | (55,682) | (44,360) | (37,071) |
| Valuation adjustments and other noncontrolling interests activity | (9,215) | 4,290 | (15,201) |
| Balance at end of year | $ 302,518 | $ 274,990 | $ 227,989 |
| Total Avista Corporation stockholders' equity | $ 1,125,784 | $ 1,051,287 | $ 996,883 |
| Noncontrolling Interests: | | | |
| Balance at beginning of year | $ (673) | $ — | $ — |
| Net income (loss) attributable to noncontrolling interests | 66 | (295) | — |
| Other | 7 | (378) | — |
| Balance at end of year | $ (600) | $ (673) | $ — |
| Total equity | $ 1,125,184 | $ 1,050,614 | $ 996,883 |
| Redeemable Noncontrolling Interests: | | | |
| Balance at beginning of year | $ 34,833 | $ 39,846 | $ 14,840 |
| Net income attributable to noncontrolling interests | 2,457 | 1,872 | 1,137 |
| Purchase of subsidiary noncontrolling interests | (2,593) | (5,450) | (6,624) |
| Valuation adjustments and other noncontrolling interests activity | 12,025 | (1,435) | 30,493 |
| Balance at end of year | $ 46,722 | $ 34,833 | $ 39,846 |

*The Accompanying Notes are an Integral Part of These Statements.*

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

## NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### Nature of Business

Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of energy, as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Utilities has electric generating facilities in Montana and northern Oregon. Avista Utilities also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeast and southwest Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility businesses, except Spokane Energy, LLC (see Note 2 for further information). Avista Capital's subsidiaries include Advantage IQ, Inc. (Advantage IQ), a 76 percent owned subsidiary as of December 31, 2010. Advantage IQ is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America. See Note 27 for business segment information.

### Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries, including Advantage IQ and other majority owned subsidiaries and variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying consolidated financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 7).

### Use of Estimates

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect amounts reported in the consolidated financial statements. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- recoverability of regulatory assets,
- stock-based compensation, and
- unbilled revenues.

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

### System of Accounts

The accounting records of the Company's utility operations are maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the state regulatory commissions in Washington, Idaho, Montana and Oregon.

### Regulation

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

### Utility Revenues

Utility revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. Revenues and resource costs from Avista Utilities' settled energy contracts that are "booked out" (not physically delivered) are reported on a net basis as part of utility revenues. The determination of the 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, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded.

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

| | 2010 | 2009 |
|---|---|---|
| Unbilled accounts receivable | $ 84,073 | $ 89,558 |

### Other Non-Utility Revenues

Service revenues from Advantage IQ are recognized over the period services are rendered. New client account setup fees are deferred and recognized over the contractual life of the related client contract. Investment earnings on funds held for clients and fees earned from third parties on payment processing are an integral part of Advantage IQ's product offerings and are recognized in revenues as earned. Revenue arrangements with multiple elements are divided into separate units of accounting if certain criteria are met, including whether the delivered element has stand-alone value to the customer and whether there is objective and reliable evidence of the fair value of the undelivered items. The consideration received is allocated among the separate units based on their respective fair values, and the applicable revenue recognition criteria are applied to each of the separate units. Revenues earned on payment processing through other service providers are reported gross on the income statement. Revenues from the other businesses are primarily derived from the operations of Advanced Manufacturing and Development (doing business as METALfx) and are recognized when the risk of loss transfers to the customer, which occurs when products are shipped.

### Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2010, 2009 and 2008.

### Depreciation

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

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Ratio of depreciation to average depreciable property | 2.84% | 2.78% | 2.77% |

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

- electric thermal production — 32 years,
- hydroelectric production — 74 years,
- electric transmission — 50 years,
- electric distribution — 38 years, and
- natural gas distribution property — 49 years.

### Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on net income. These taxes are generally based on revenues or the value of property.

**Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense and totaled the following amounts for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Utility taxes | $ 49,953 | $ 56,818 | $ 53,855 |

### Allowance for Funds Used During Construction

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

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Effective AFUDC rate | 8.25% (1) | 8.22% | 8.20% |

*(1) Rate was effective from January 1, 2010 to November 30, 2010. Effective December 1, 2010, rate was changed to 7.91%.*

### Income Taxes

A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company's consolidated income tax returns. The deferred income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

### Stock-Based Compensation

Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity or liability instruments issued. See Note 23 for further information.

### Other Income (Expense) — Net

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Interest income | $ 1,159 | $ 1,614 | $ 3,262 |
| Interest on regulatory deferrals | 248 | 2,935 | 3,671 |
| Interest on income tax settlement | — | — | 5,749 |
| Equity-related AFUDC | 3,353 | 3,078 | 5,692 |
| Net gain (loss) on investments | (3,297) | (837) | (1,368) |
| Dues and donations | (4,164) | (1,405) | (956) |
| Other expense | (5,686) | (5,472) | (6,438) |
| Other income | 430 | 889 | 834 |
| Total | $ (7,957) | $ 802 | $ 10,446 |

### Earnings per Common Share Attributable to Avista Corporation

Basic earnings per common share attributable to Avista Corporation is computed by dividing net income attributable to Avista Corporation by the weighted average number of common shares outstanding for the period. Diluted earnings per common share attributable to Avista Corporation is calculated by dividing net income attributable to Avista Corporation (adjusted for the effect of potentially dilutive securities issued by subsidiaries) by diluted weighted average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and contingent stock awards. See Note 22 for earnings per common share calculations.

### Cash and Cash Equivalents

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

### Allowance for Doubtful Accounts

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

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Allowance as of the beginning of the year | $ 42,928 | $ 45,062 | $ 42,582 |
| Additions expensed during the year | 5,194 | 5,344 | 6,595 |
| Net deductions | (3,239) | (7,478) | (4,115) |
| Allowance as of the end of the year | $ 44,883 | $ 42,928 | $ 45,062 |

### Materials and Supplies, Fuel Stock and Natural Gas Stored

**Inventories of materials and supplies, fuel stock and natural gas stored are recorded at the lower of cost or market, primarily using the average cost method and consisted of the following as of December 31 (dollars in thousands):**

| | 2010 | 2009 |
|---|---|---|
| Materials and supplies | $ 24,998 | $ 20,281 |
| Fuel stock | 6,289 | 4,294 |
| Natural gas stored | 17,243 | 12,707 |
| Total | $ 48,530 | $ 37,282 |

### Funds Held for Customers and Customer Fund Obligations

In connection with the bill paying services, Advantage IQ collects funds from its customers and remits the funds to the appropriate utility or other service provider. The funds collected are invested and classified as funds held for customers and a related liability for customer fund obligations is recorded. Funds held for customers include cash and cash equivalent investments.

### Utility Plant in Service

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

### Asset Retirement Obligations

The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense for which the Company has not recorded asset retirement obligations (see Note 9).

**The Company had estimated retirement costs (that do not represent legal or contractual obligations) included as a regulatory liability on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):**

| | 2010 | 2009 |
|---|---|---|
| Regulatory liability for utility plant retirement costs | $ 223,131 | $ 217,176 |

### Goodwill

Goodwill arising from acquisitions represents the excess of the purchase price over the estimated fair value of net assets acquired. The Company evaluates goodwill for impairment using a discounted cash flow model on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2010 for the other businesses and as of December 31, 2010 for Advantage IQ and determined that goodwill was not impaired at that time.

**The changes in the carrying amount of goodwill are as follows (dollars in thousands):**

| | Advantage IQ | Other | Accumulated Impairment Losses | Total |
|---|---|---|---|---|
| Balance as of January 1, 2009 | $ 15,886 | $ 12,979 | $ (7,733) | $ 21,132 |
| Goodwill acquired during the year | 4,209 | — | — | 4,209 |
| Adjustments | (623) | — | — | (623) |
| Balance as of the December 31, 2009 | 19,472 | 12,979 | (7,733) | 24,718 |
| Goodwill acquired during the year | 1,113 | — | — | 1,113 |
| Adjustments | 104 | — | — | 104 |
| Balance as of the December 31, 2010 | $ 20,689 | $ 12,979 | $ (7,733) | $ 25,935 |

Accumulated impairment losses are attributable to the other businesses. The goodwill acquired in 2009 was related to Advantage IQ's acquisition of substantially all of the assets and liabilities of Ecos Consulting, Inc. (Ecos), a Portland, Oregon-based energy efficiency solutions provider. The adjustment to goodwill recorded in 2009 represents final adjustments for Advantage IQ's acquisition of Cadence Network based upon the completion of the review of the fair market values of relevant assets and liabilities identified as of the acquisition date. The goodwill acquired in 2010 was related to Advantage IQ's acquisition of substantially all the assets and liabilities of The Loyalton Group on December 31, 2010. Final accounting is pending the completion of further review of the fair values of the relevant assets and liabilities identified as of the acquisition date.

**Other Intangibles**

Other Intangibles primarily represent the amounts assigned to client relationships related to the Advantage IQ acquisition of Cadence Network in 2008 (estimated amortization period of 12 years) and Ecos in 2009 (estimated amortization period of 3 years), software development costs (estimated amortization period of 5 to 7 years) and other. Other Intangibles are included in other property and investments — net on the Consolidated Balance Sheets.

**Amortization expense related to Other Intangibles was as follows for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Other intangible amortization | $ 3,755 | $ 2,412 | $ 1,149 |

**The following table details the future estimated amortization expense related to Other Intangibles (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|
| Estimated amortization expense | $ 4,172 | $ 3,946 | $ 3,233 | $ 2,710 | $ 1,696 |

**The gross carrying amount and accumulated amortization of Other Intangibles as of December 31, 2010 and 2009 are as follows (dollars in thousands):**

| | 2010 | 2009 |
|---|---|---|
| Client relationships | $ 11,459 | $ 10,259 |
| Software development costs | 19,139 | 16,496 |
| Other | 1,450 | 1,371 |
| Total other intangibles | 32,048 | 28,126 |
| Less accumulated amortization | (11,947) | (8,192) |
| Total other intangibles — net | $ 20,101 | $ 19,934 |

**Regulatory Deferred Charges and Credits**

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

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

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

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

See Note 26 for further details of regulatory assets and liabilities.

### Investment in Exchange Power-Net

The investment in exchange power represents the Company's previous investment in Washington Public Power Supply System Project 3 (WNP-3), a nuclear project that was terminated prior to completion. Under a settlement agreement with the Bonneville Power Administration in 1985, Avista Utilities began receiving power in 1987, for a 32.5-year period, related to its investment in WNP-3. Through a settlement agreement with the Washington Utilities and Transportation Commission (WUTC) in the Washington jurisdiction, Avista Utilities is amortizing the recoverable portion of its investment in WNP-3 (recorded as investment in exchange power) over a 32.5-year period that began in 1987. For the Idaho jurisdiction, Avista Utilities fully amortized the recoverable portion of its investment in exchange power.

### Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt.

### Unamortized Debt Repurchase Costs

For the Company's Washington regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are recovered through retail rates as a component of interest expense.

### Redeemable Noncontrolling Interests

This item represents the estimated fair value of redeemable stock and stock options of Advantage IQ issued under its employee stock incentive plan and to the previous owners of Cadence Network. See Notes 5 and 23 for further information. The presentation of the buyback of Advantage IQ shares was corrected in the Consolidated Statements of Cash Flows for 2009 and 2008 by reclassifying the purchase of subsidiary noncontrolling interest of $5.5 million for 2009 and $6.6 million for 2008 from investing to financing activities.

### Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss, net of tax, consisted of the unfunded benefit obligation for pensions and other postretirement benefit plans as of December 31, 2010 and 2009.

### Reclassifications

The Company made reclassifications in the Operating Activities sections of the Consolidated Statements of Cash Flows for 2009 and 2008 to conform to the 2010 presentation. In particular, amortization of investment in exchange power and stock-based compensation are presented as their own line items. They were previously included in other.

## NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2009, the Company adopted amendments to the accounting for business combinations (Accounting Standards Codification (ASC) 805-10) that addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. This requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the transaction at the acquisition date, measured at their fair values as of that date, with limited exceptions. The acquisition of Ecos was accounted for in accordance with the provisions of the amended accounting standards, which did not have a material effect on the consolidated financial statements.

Effective January 1, 2009, the Company adopted accounting standards that amended previous accounting guidance to establish accounting and reporting standards for a noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary (ASC 810-10). This clarifies that a noncontrolling interest in a subsidiary is an ownership in the consolidated entity that should be reported as equity in the consolidated financial statements. The adoption of these amended accounting standards had no material impact on the Company's financial condition and results of operations. However, it did impact the presentation and disclosure of noncontrolling interests in the Company's consolidated financial statements. The presentation and disclosure requirements were retrospectively applied to the consolidated financial statements. The net income attributable to noncontrolling interests primarily relates to third party shareholders of Advantage IQ.

Effective January 1, 2010, the Company adopted Accounting Standards Update (ASU) No. 2009-16, "Transfers and Servicing" (ASC Topic 860). This ASU amends certain provisions of ASC 860 related to accounting for transfers of financial assets and a transferor's continuing involvement in transferred financial assets. In particular, the Company evaluated its accounts receivable sales financing facility (see Note 13) and determined that the transactions no longer meet the criteria of sales of financial assets. As such, any transactions will be accounted for as secured borrowings. During 2010, the Company did not borrow any funds under the revolving agreement. As such, the adoption of this ASU did not have any impact on the Company's financial condition, results of operations and cash flows.

Effective January 1, 2010, the Company adopted ASU No. 2009-17, "Consolidations (Topic 810) — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities (VIEs)." This ASU carries forward the scope of ASC 810, with the addition of entities previously considered qualifying special-purpose entities, as the concept of these entities was eliminated in ASU No. 2009-16 (ASC 860). The amendments required the Company to reconsider previous conclusions relating to the consolidation of VIEs, whether the Company is the VIE's primary beneficiary, and what type of financial statement disclosures are required.

The Company evaluated its power purchase agreement (PPA) for the Lancaster Project, a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho, owned by an unrelated third-party (Rathdrum Power LLC). During development and at the time of the commencement of commercial operations in September 2001, Avista Power, LLC, another subsidiary of Avista Corp., owned 49 percent of the equity in the Lancaster Project. The Lancaster Project was financed with 80 percent debt and 20 percent equity. In October 2006, Avista Power, LLC sold its equity ownership interest in the Lancaster Project.

All of the output from the Lancaster Plant was contracted to Avista Turbine Power, Inc. (ATP), a subsidiary of Avista Corp., through 2026 under the PPA. In September 2001, the rights and obligations under the PPA were assigned to Avista Energy, Inc. (Avista Energy) another subsidiary of Avista Corp. Beginning in July 2007 through the end of 2009, ATP conveyed the majority of its rights and obligations under the PPA to Shell Energy in connection with the sale of the majority of Avista Energy's contracts and ongoing operations to Shell Energy. ATP conveyed these rights and obligations to Avista Corp. (Avista Utilities) beginning in January 2010. Effective December 1, 2010, the rights and obligations under the PPA were assigned to Avista Corp.

Since Avista Corp. has a variable interest in the PPA, Avista Corp. made an evaluation of which interest holders have the power to direct the activities that most significantly impact the economic performance of the entity and which interest holders have the obligation to absorb losses or receive benefits that could be significant to the entity. Avista Corp. pays a fixed capacity and operations and maintenance payment and certain monthly variable costs under the PPA. Under the terms of the PPA, Avista Corp. makes the dispatch decisions, provides all natural gas fuel and receives all of the electric energy output from the Lancaster Plant. However, Rathdrum Power LLC (the owner) controls the daily operation of the Lancaster Plant and makes operating and maintenance decisions. Rathdrum Power LLC controls all of the rights and obligations of the Lancaster Plant after the expiration of the PPA in 2026. It is estimated that the plant will have 15 to 25 years of useful life after that time. Rathdrum Power LLC bears the maintenance risk of the plant and will receive the residual value of the Lancaster Plant. Avista Corp. has no debt or equity investments in the Lancaster Project and does not provide financial support through liquidity arrangements or other commitments (other than the PPA). Based on its analysis, Avista Corp. does not consider itself to be the primary beneficiary of the Lancaster Plant. The Company has a future contractual obligation of approximately $362 million under the PPA (representing the fixed capacity and operations and maintenance payments through 2026) and believes this would be its maximum exposure to loss. However, the Company believes that such costs will be recovered through retail rates.

The implementation of amendments to ASC 810 results in the Company including Spokane Energy, LLC (Spokane Energy) in its consolidated financial statements effective January 1, 2010. 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 (PGE). Under the terms of the contract, Peaker, LLC (Peaker) purchases capacity from Avista Corp. and sells capacity to Spokane Energy, who in turn, sells the related capacity to PGE. Peaker acts as an intermediary to fulfill certain regulatory requirements between Spokane Energy and Avista Corp.

To provide funding to acquire the contract from Avista Corp., Spokane Energy borrowed $145.0 million from a funding trust. The transaction is structured such that Spokane Energy bears full recourse risk for a loan that matures in January 2015. Avista Corp. bears no recourse related to this loan. In December 1998, Spokane Energy acquired the contract from Avista Corp. to supply electric energy capacity to PGE through December 31, 2016. The cost of acquiring the energy contract is being amortized and matched with sales revenue over the life of the contract using the effective interest method. Avista Corp. acts as the servicer under the contract and performs scheduling, billing and collection functions. In exchange for such services, Spokane Energy pays a monthly servicing fee to Avista Corp. The servicing fee is less than $0.1 million per year.

In December 1998, Avista Corp. received $143.4 million of cash from Spokane Energy related to the monetization of the contract. Pursuant to orders from the Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC), Avista Corp. fully amortized this amount by the end of 2002.

Avista Corp. did not previously consolidate Spokane Energy because Spokane Energy met the definition of a qualified special purpose entity (QSPE). As the amendments to ASC 810 and 860 eliminated the concept of a QSPE, Avista Corp. evaluated Spokane Energy for consolidation as a variable interest entity and determined that it was required to consolidate the entity. This determination was based primarily on Avista Corp. controlling the activities of Spokane Energy, owning all of the member capital of Spokane Energy, and receiving the majority of the residual benefits upon liquidation of the entity.

**The consolidation of Spokane Energy resulted in the following effects on the Consolidated Balance Sheet as of December 31, 2010 (dollars in thousands):**

| | | |
|---|---|---|
| Current portion of long-term energy contract receivable | $ | 9,645 |
| Other current assets | | 2,034 |
| Long-term energy capacity contract receivable | | 62,525 |
| Other property and investments-net | | 1,100 |
| Total assets | $ | 75,304 |
| Other current liabilities | $ | (706) |
| Current portion of nonrecourse long-term debt | | 12,463 |
| Nonrecourse long-term debt | | 46,471 |
| Other non-current liabilities and deferred credits [1] | | 17,076 |
| Total liabilities | $ | 75,304 |

*(1) Consists of a regulatory liability recorded for the cumulative retained earnings of Spokane Energy that the Company will flow through regulatory accounting mechanisms in future periods.*

Due to the expected impact on regulatory accounting mechanisms in future periods, the consolidation of Spokane Energy did not have any effect on net income for 2010.

**The consolidation of Spokane Energy increased (decreased) the following line items in the Consolidated Statements of Income for 2010 (dollars in thousands):**

| | | |
|---|---|---|
| Utility revenues | $ | (1,800) |
| Non-utility energy revenues | | 18,702 |
| Non-utility operating expenses — resource costs | | 11,389 |
| Non-utility operating expenses — other operating expenses | | 16 |
| Income from operations | | 5,497 |
| Interest expense | | 5,508 |
| Other expense — net | | (11) |

For 2010, the regulatory liability recorded for the operations of Spokane Energy increased by $2.5 million.

The Company also evaluated several low-income housing project investments and determined that it should no longer consolidate these entities based upon the amendments to ASC 810. The Company determined that it was not the primary beneficiary because it lacks the power to direct any of the activities of the entities. The deconsolidation of the low-income housing project entities reduced current assets by $0.9 million, other property and investments-net by $1.7 million and long-term debt by $2.6 million effective January 1, 2010. The deconsolidation did not have any impact on the Company's equity or net income.

Effective January 1, 2010, the Company adopted ASU No. 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements." This ASU amends guidance related to the disclosures of fair value measurements. In particular, it amends ASC 820-10 to clarify existing disclosures and provides for further disaggregation within classes of assets and liabilities, and further disclosure about inputs and valuation techniques. It also requires disclosure of significant transfers between Level 1 and Level 2 and separate disclosure of purchases, sales, issuances and settlements in the reconciliation of Level 3 activity (this will be required beginning in 2011). See Note 20 for the Company's fair value disclosures.

## NOTE 3. DISPOSITION OF AVISTA ENERGY

On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy. In connection with the transaction, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 24), existing litigation, tax liabilities, and matters related to natural gas storage rights. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. The Guaranty will terminate April 30, 2011 except for claims made prior to termination. The Company has not recorded any liability related to this guaranty.

## NOTE 4. IMPAIRMENT OF ASSETS

During the fourth quarter of 2009, the Company recorded a $3.0 million impairment charge for a commercial building (included in its other businesses). This impairment charge is included in non-utility other operating expenses in the Consolidated Statements of Income. Due to an increase in vacancy rates and a reduction in current and projected cash flows, the Company determined that it needed to evaluate the property for impairment. The impairment charge reduced the carrying value of the commercial building to its estimated fair value, which is $2.7 million. The estimated fair value of the commercial building was determined using a discounted cash flow model with Level 3 inputs. See Note 20 for a discussion of the fair value hierarchy.

## NOTE 5. ADVANTAGE IQ ACQUISITIONS

Effective July 2, 2008, Advantage IQ completed the acquisition of Cadence Network, a privately held, Cincinnati-based energy and expense management company. As consideration, the owners of Cadence Network received a 25 percent ownership interest in Advantage IQ. The total value of the transaction was $37 million.

The acquisition of Cadence Network was funded with the issuance of Advantage IQ common stock. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Advantage IQ common stock redeemed during July 2011 or July 2012 if Advantage IQ is not liquidated through either an initial public offering or sale of the business to a third party. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Advantage IQ at the time of the redemption election as determined by certain independent parties. Additionally, the certain minority shareholders and option holders of Advantage IQ have the right to put their shares back to Advantage IQ at their discretion (refer to Note 23 for further information).

**The following details redeemable noncontrolling interests as of December 31 (dollars in thousands):**

| | | 2010 | | 2009 |
|---|---|---|---|---|
| Previous owners of Cadence Network | $ | 38,098 | $ | 27,877 |
| Stock options and other outstanding redeemable stock | | 8,624 | | 6,956 |
| Total redeemable noncontrolling interests | $ | 46,722 | $ | 34,833 |

In January 2011, the other owners of Advantage IQ (including Avista Capital) purchased shares held by the one of the previous owners of Cadence Network (that owned 4.5 percent of Advantage IQ). Avista Capital's portion of the purchase was $5.6 million.

The acquired assets and liabilities assumed of Cadence Network were recorded at their respective estimated fair values as of the date of acquisition (July 2, 2008). The results of operations of Cadence Network are included in the consolidated financial statements beginning in the third quarter of 2008.

On August 31, 2009, Advantage IQ acquired substantially all of the assets and liabilities of Ecos Consulting, Inc. (Ecos), a Portland, Oregon-based energy efficiency solutions provider. The acquisition of Ecos was funded primarily through borrowings under Advantage IQ's committed credit agreement. Under the terms of the transaction, the assets and liabilities of Ecos were acquired by a wholly owned subsidiary of Advantage IQ.

The acquired assets and liabilities assumed of Ecos were recorded at their respective estimated fair values as of the date of acquisition (August 31, 2009). The results of operations of Ecos are included in the consolidated financial statements beginning in September 2009.

On December 31, 2010, Advantage IQ acquired substantially all of the assets and liabilities of The Loyalton Group, a Minneapolis-based energy management firm known for its energy procurement and price risk management solutions. The acquisition of The Loyalton Group was funded primarily through available cash at Advantage IQ.

The acquired assets and liabilities assumed of the Loyalton Group were preliminarily recorded at their respective estimated fair values as of the date of acquisition (December 31, 2010). Final accounting is pending the completion of further review of the fair values of the relevant assets and liabilities identified as of the acquisition date. The results of operations of The Loyalton Group will be included in the consolidated financial statements beginning in January 2011. Pro forma disclosures reflecting the effects of the acquisition of The Loyalton Group are not presented, as the acquisition is not material to Avista Corp.'s consolidated financial condition or results of operations.

In January 2011, Advantage IQ acquired substantially all of the assets and liabilities of Building Knowledge Networks, a Seattle-based real-time building energy management services provider. The acquisition of Building Knowledge Networks was funded through available cash at Advantage IQ. Pro forma disclosures reflecting the effects of the acquisition of Building Knowledge Networks are not presented, as the acquisition is not material to Avista Corp.'s consolidated financial condition or results of operations.

## NOTE 6. DERIVATIVES AND RISK MANAGEMENT

**Energy Commodity Derivatives**

Avista Utilities is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Market risk may also be influenced by market participants' nonperformance of their contractual obligations and commitments, which affects the supply of, or demand for, the commodity. Avista Utilities utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these commodity price exposures. The Company has an energy resources risk policy and control procedures to manage these risks. The Company's Risk Management Committee establishes the Company's energy resources risk policy and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other management. The Audit Committee of the Company's Board of Directors periodically reviews and discusses risk assessment and risk management policies, including the Company's material financial and accounting risk exposures and the steps management has undertaken to control them.

As part of its resource procurement and management operations in the electric business, Avista Utilities engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Utilities' load obligations and the use of these resources to capture available economic value. Avista Utilities sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring and balancing resources to serve its load obligations. These transactions range from terms of one hour up to multiple years.

Avista Utilities makes continuing projections of:

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

On the basis of these projections, Avista Utilities makes 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.

Avista Utilities' optimization process includes entering into hedging transactions to manage risks.

As part of its resource procurement and management operations in the natural gas business, Avista Utilities makes continuing projections of its natural gas loads and assesses available natural gas resources. Forward natural gas contracts are typically for monthly delivery periods. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Utilities plans and executes a series of transactions to hedge a significant portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Utilities also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets. Natural gas resource optimization activities include:

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

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

The WUTC and the IPUC issued accounting orders authorizing Avista Utilities to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Utilities 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 Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. Regulatory assets are assessed regularly and are probable for recovery through future rates.

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

**The following table presents the underlying energy commodity derivative volumes as of December 31, 2010 that are expected to settle in each respective year (in thousands of MWhs and mmBTUs):**

| | Purchases | | | | Sales | | | |
|---|---|---|---|---|---|---|---|---|
| | Electric Derivatives | | Gas Derivatives | | Electric Derivatives | | Gas Derivatives | |
| Year | Physical MWH | Financial MWH | Physical mmBTUs | Financial mmBTUs | Physical MWH | Financial MWH | Physical mmBTUs | Financial mmBTUs |
| 2011 | 949 | 1,144 | 35,324 | 41,593 | 267 | 142 | 13,426 | 46,525 |
| 2012 | 551 | 668 | 11,526 | 24,845 | 286 | 62 | 1,525 | 19,510 |
| 2013 | 368 | — | 6,008 | 6,275 | 286 | — | 1,500 | 1,125 |
| 2014 | 366 | — | 2,483 | 900 | 286 | — | 1,475 | — |
| 2015 | 379 | — | 675 | — | 286 | — | — | — |
| Thereafter | 1,315 | — | — | — | 1,017 | — | — | — |

**Foreign Currency Exchange Contracts**

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

**The following table summarizes the foreign currency hedges that the Company has entered into as of December 31 (dollars in thousands):**

| | 2010 | 2009 |
|---|---|---|
| Number of contracts | 29 | 24 |
| Notional amount (in United States dollars) | $ 10,916 | $ 10,210 |
| Notional amount (in Canadian dollars) | 10,989 | 10,637 |
| Derivative in other current assets (liabilities) | 116 | (50) |

**Interest Rate Swap Agreements**

Avista Corp. enters into forward-starting interest rate swap agreements to manage the risk associated with changes in interest rates and the impact on future interest payments. These interest rate swap agreements relate to the interest payments for anticipated debt issuances. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with changes in interest rates.

**The following table summarizes the interest rate swaps that the Company has entered into as of December 31, 2010 (dollars in thousands):**

| Entered | Notional | Number of Contracts | Mandatory Cash Settlement Date |
|---|---|---|---|
| May/June 2010 | $ 50,000 | 2 | July 2012 |

The Company did not have any interest rate swap contracts outstanding as of December 31, 2009. In September 2009, the Company cash settled interest rate swap contracts (notional amount of $200.0 million) and received a total of $10.8 million. The interest rate swap contracts were settled concurrently with the issuance of $250.0 million of First Mortgage Bonds (see Note 15). The settlement of the interest rate swaps was deferred as a regulatory liability (included as part of long-term debt) and is being amortized as a component of interest expense over the life of the associated debt issued in accordance with regulatory accounting practices.

Under the terms of the outstanding interest rate swap agreements, the value of the interest rate swaps is determined based upon Avista Corp. paying a fixed rate and receiving a variable rate based on LIBOR for a term of ten years. As of December 31, 2010, Avista Corp. had a long-term derivative asset and an offsetting regulatory liability of $0.1 million, as well as a long-term derivative liability and an offsetting regulatory asset of less than $0.1 million on the Consolidated Balance Sheet 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.

### Derivative Instruments Summary

**The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheet as of December 31, 2010 (in thousands):**

| | | | Fair Value | |
|---|---|---|---|---|
| **Derivative** | **Balance Sheet Location** | **Asset** | **Liability** | **Net Asset (Liability)** |
| Foreign currency contracts | Other current assets | $ 116 | $ — | $ 116 |
| Interest rate contracts | Other property and investments-net | 127 | — | 127 |
| Interest rate contracts | Other non-current liabilities and deferred credits | — | (53) | (53) |
| Commodity contracts | Current utility energy commodity derivative assets | 6,293 | (3,701) | 2,592 |
| Commodity contracts | Non-current utility energy commodity derivative assets | 21,249 | (5,988) | 15,261 |
| Commodity contracts | Current utility energy commodity derivative liabilities | 5,934 | (57,417) | (51,483) |
| Commodity contracts | Other non-current liabilities and deferred credits | 1,386 | (32,371) | (30,985) |
| Total derivative instruments recorded on the balance sheet | | $ 35,105 | $ (99,530) | $ (64,425) |

**The following table presents the fair values and locations of derivative instruments recorded on the Consolidated Balance Sheet as of December 31, 2009 (in thousands):**

| | | | Fair Value | |
|---|---|---|---|---|
| **Derivative** | **Balance Sheet Location** | **Asset** | **Liability** | **Net Asset (Liability)** |
| Foreign currency contracts | Other current liabilities | $ — | $ (50) | $ (50) |
| Commodity contracts | Current utility energy commodity derivative assets | 8,976 | (1,219) | 7,757 |
| Commodity contracts | Non-current utility energy commodity derivative assets | 53,765 | (8,282) | 45,483 |
| Commodity contracts | Current utility energy commodity derivative liabilities | 5,783 | (21,870) | (16,087) |
| Commodity contracts | Other non-current liabilities and deferred credits | 650 | (3,521) | (2,871) |
| Total derivative instruments recorded on the balance sheet | | $ 69,174 | $ (34,942) | $ 34,232 |

### Exposure to Demands for Collateral

The Company's derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a downgrade in the Company's credit ratings or adverse changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to minimize capital requirements.

Certain of the Company's derivative instruments contain provisions that require the Company to maintain an investment grade credit rating from the major credit rating agencies. If the Company's credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of December 31, 2010 was $62.1 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2010, the Company would be required to post $42.1 million of collateral to its counterparties.

### Credit Risk

Credit risk relates to the potential losses that the Company would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy or make financial settlements. The Company often extends credit to counterparties and customers and is exposed to the risk that it may not be able to collect amounts owed to the Company. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. Credit risk includes potential counterparty default due to circumstances:

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

Should a counterparty, customer or supplier fail to perform, the Company may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices. The Company seeks 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 its transactions on exchanges with clearing arrangements that essentially eliminate counterparty default risk.

These 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. The Company also uses standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty or affiliated group.

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

- electric utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions, and
- energy marketing and trading companies.

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

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

Cash deposits from counterparties totaled $1.2 million as of December 31, 2010 and $3.2 million as of December 31, 2009. These funds were held by Avista Utilities to mitigate the potential impact of counterparty default risk. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of non-cash collateral.

## NOTE 7. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income.

**The Company's share of utility plant in service for Colstrip and accumulated depreciation were as follows as of December 31 (dollars in thousands):**

| | 2010 | 2009 |
|---|---|---|
| Utility plant in service | $ 336,796 | $ 334,773 |
| Accumulated depreciation | (219,770) | (209,587) |

## NOTE 8. PROPERTY, PLANT AND EQUIPMENT

**The balances of the major classifications of property, plant and equipment are detailed in the following table as of December 31 (dollars in thousands):**

| | 2010 | 2009 |
|---|---|---|
| Avista Utilities: | | |
| Electric production | $ 1,076,829 | $ 1,060,495 |
| Electric transmission | 496,495 | 471,686 |
| Electric distribution | 1,084,082 | 1,023,541 |
| Electric construction work-in-progress (CWIP) and other | 183,479 | 169,852 |
| Electric total | 2,840,885 | 2,725,574 |
| Natural gas underground storage | 32,928 | 35,390 |
| Natural gas distribution | 653,075 | 630,720 |
| Natural gas CWIP and other | 56,899 | 50,954 |
| Natural gas total | 742,902 | 717,064 |
| Common plant (including CWIP) | 192,149 | 167,075 |
| Total Avista Utilities | 3,775,936 | 3,609,713 |
| Advantage IQ [1] | 27,222 | 22,813 |
| Other [1] | 36,962 | 41,913 |
| Total | $ 3,840,120 | $ 3,674,439 |

*(1) Included in other property and investments-net on the Consolidated Balance Sheets. Accumulated depreciation was $22.4 million and $18.6 million for Advantage IQ and $16.6 million and $19.1 million for the other businesses.*

## NOTE 9. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded since asset retirement costs are recovered through rates charged to customers. The regulatory assets do not earn a return.

Specifically, the Company has recorded liabilities for future asset retirement obligations to:

- restore ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease,
- remove asbestos at the corporate office building, and
- dispose of PCBs in certain transformers.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

**The following table documents the changes in the Company's asset retirement obligation during the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Asset retirement obligation at beginning of year | $ 3,971 | $ 4,208 | $ 3,990 |
| New liability recognized | 19 | — | — |
| Liability adjustment due to revision in estimated cash flows | — | — | — |
| Liability settled | (460) | (499) | (29) |
| Accretion expense | 357 | 262 | 247 |
| Asset retirement obligation at end of year | $ 3,887 | $ 3,971 | $ 4,208 |

## NOTE 10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $21 million in cash to the pension plan in 2010, $48 million in 2009 and $28 million in 2008. The Company expects to contribute $26 million in cash to the pension plan in 2011.

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

**The Company expects that benefit payments under the pension plan and the SERP will total (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Total 2016-2020 |
|---|---|---|---|---|---|---|
| Expected benefit payments | $ 19,343 | $ 20,521 | $ 21,824 | $ 23,105 | $ 24,620 | $ 145,063 |

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

In 2009, the Company reviewed the mortality table utilized in the actuarial calculations. The Company determined that the RP-2000 combined healthy mortality tables for males and females should be replaced with the RP-2000 combined healthy mortality tables for males and females projected to 2010 using scale AA. The change resulted in an increase of $6.6 million to the pension benefit obligation as of December 31, 2009.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The Company elected to amortize the transition obligation of $34.5 million over a period of twenty years, beginning in 1993.

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

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

**The Company expects that benefit payments under other postretirement benefit plans will total (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Total 2016-2020 |
|---|---|---|---|---|---|---|
| Expected benefit payments | $ 4,695 | $ 4,495 | $ 4,488 | $ 4,489 | $ 4,520 | $ 22,439 |

The Company expects to contribute $4.7 million to other postretirement benefit plans in 2011, representing expected benefit payments to be paid during the year.

The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

**The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2010 and 2009 and the components of net periodic benefit costs for the years ended December 31, 2010, 2009 and 2008 (dollars in thousands):**

| | Pension Benefits | | Other Post-retirement Benefits | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **Change in benefit obligation:** | | | | |
| Benefit obligation as of beginning of year | $ 378,235 | $ 353,572 | $ 39,560 | $ 38,953 |
| Service cost | 11,609 | 10,496 | 684 | 803 |
| Interest cost | 23,231 | 21,770 | 2,624 | 2,364 |
| Actuarial loss | 38,547 | 9,610 | 21,657 | 1,676 |
| Transfer of accrued vacation | — | — | 367 | 98 |
| Benefits paid | (18,131) | (17,213) | (4,553) | (4,334) |
| Benefit obligation as of end of year | $ 433,491 | $ 378,235 | $ 60,339 | $ 39,560 |
| **Change in plan assets:** | | | | |
| Fair value of plan assets as of beginning of year | $ 272,732 | $ 190,637 | $ 20,394 | $ 16,048 |
| Actual return on plan assets | 29,846 | 50,053 | 2,481 | 4,346 |
| Employer contributions | 21,000 | 48,000 | — | — |
| Benefits paid | (16,866) | (15,958) | — | — |
| Fair value of plan assets as of end of year | $ 306,712 | $ 272,732 | $ 22,875 | $ 20,394 |
| Funded status | $ (126,779) | $ (105,503) | $ (37,464) | $ (19,166) |
| Unrecognized net actuarial loss | 149,819 | 126,926 | 35,149 | 15,772 |
| Unrecognized prior service cost | 1,140 | 1,790 | (1,154) | (1,303) |
| Unrecognized net transition obligation | — | — | 1,011 | 1,516 |
| Prepaid (accrued) benefit cost | 24,180 | 23,213 | (2,458) | (3,181) |
| Additional liability | (150,959) | (128,716) | (35,006) | (15,985) |
| Accrued benefit liability | $ (126,779) | $ (105,503) | $ (37,464) | $ (19,166) |
| Accumulated pension benefit obligation | $ 377,606 | $ 331,081 | — | — |
| Accumulated postretirement benefit obligation: | | | | |
| For retirees | | | $ 27,921 | $ 18,377 |
| For fully eligible employees | | | $ 15,618 | $ 9,290 |
| For other participants | | | $ 16,800 | $ 11,893 |
| **Included in accumulated comprehensive loss (income) (net of tax):** | | | | |
| Unrecognized net transition obligation | $ — | $ — | $ 657 | $ 985 |
| Unrecognized prior service cost | 741 | 1,163 | (750) | (847) |
| Unrecognized net actuarial loss | 97,382 | 82,502 | 22,847 | 10,252 |
| Total | 98,123 | 83,665 | 22,754 | 10,390 |
| Less regulatory asset | (92,570) | (80,041) | (23,981) | (11,664) |
| Accumulated other comprehensive loss (income) | $ 5,553 | $ 3,624 | $ (1,227) | $ (1,274) |

| | Pension Benefits | | Other Post-retirement Benefits | |
|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 |
| **Weighted average assumptions as of December 31:** | | | | |
| Discount rate for benefit obligation | 5.69% | 6.29% | 5.50% | 6.00% |
| Discount rate for annual expense | 6.28% | 6.25% | 6.00% | 6.25% |
| Expected long-term return on plan assets | 7.75% | 8.50% | 7.75% | 8.50% |
| Rate of compensation increase | 4.72% | 4.65% | | |
| Medical cost trend pre-age 65 — initial | | | 8.00% | 8.50% |
| Medical cost trend pre-age 65 — ultimate | | | 5.00% | 5.00% |
| Ultimate medical cost trend year pre-age 65 | | | 2017 | 2017 |
| Medical cost trend post-age 65 — initial | | | 8.00% | 8.50% |
| Medical cost trend post-age 65 — ultimate | | | 6.00% | 6.00% |
| Ultimate medical cost trend year post-age 65 | | | 2015 | 2015 |

| | 2010 | 2009 | 2008 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|---|
| **Components of net periodic benefit cost:** | | | | | | |
| Service cost | $ 11,609 | $ 10,496 | $ 10,209 | $ 684 | $ 803 | $ 772 |
| Interest cost | 23,231 | 21,770 | 20,812 | 2,624 | 2,364 | 2,371 |
| Expected return on plan assets | (21,381) | (17,612) | (21,138) | (1,581) | (1,364) | (1,931) |
| Transition obligation recognition | — | — | — | 505 | 505 | 505 |
| Amortization of prior service cost | 650 | 654 | 654 | (149) | (149) | (149) |
| Net loss recognition | 7,189 | 10,539 | 3,345 | 1,379 | 1,279 | 575 |
| Net periodic benefit cost | $ 21,298 | $ 25,847 | $ 13,882 | $ 3,462 | $ 3,438 | $ 2,143 |

**Plan Assets**

The Finance Committee of the Company's Board of Directors establishes investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for managing/monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested 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 target investment allocation percentages by asset classes as indicated in the table below:**

| | 2010 | 2009 |
|---|---|---|
| Equity securities | 51% | 51% |
| Debt securities | 31% | 31% |
| Real estate | 5% | 5% |
| Absolute return | 10% | 10% |
| Other | 3% | 3% |

The market-related value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund's net assets by its units outstanding at the valuation date. The fair value of the closely held investments and partnership interests is based upon the allocated share of the fair value of the underlying assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses.

The market-related value of pension plan assets invested in real estate was determined by the investment manager based on three basic approaches:

- current cost of reproducing a property less deterioration and functional economic obsolescence,
- capitalization of the property's net earnings power, and
- value indicated by recent sales of comparable properties in the market.

The market-related value of pension plan assets was determined as of December 31, 2010 and 2009.

**The following table discloses by level within the fair value hierarchy (refer to Note 20 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2010 at fair value (dollars in thousands):**

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Cash equivalents | $ 335 | $ — | $ — | $ 335 |
| Mutual funds: | | | | |
| Fixed income securities | 96,026 | — | — | 96,026 |
| U.S. equity securities | 104,232 | — | — | 104,232 |
| International equity securities | 53,964 | — | — | 53,964 |
| Absolute return (1) | 12,662 | — | — | 12,662 |
| Commodities (2) | 7,133 | — | — | 7,133 |
| Common/collective trusts: | | | | |
| Fixed income securities | — | 13,653 | — | 13,653 |
| Absolute return (1) | — | — | 95 | 95 |
| Real estate | — | — | 423 | 423 |
| Partnership/closely held investments: | | | | |
| Absolute return (1) | — | — | 16,917 | 16,917 |
| Private equity funds (3) | — | — | 1,272 | 1,272 |
| Total | $ 274,352 | $ 13,653 | $ 18,707 | $ 306,712 |

**The following table discloses by level within the fair value hierarchy (refer to Note 20 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2009 at fair value (dollars in thousands):**

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Cash equivalents | $ 19 | $ — | $ — | $ 19 |
| Mutual funds: | | | | |
| Fixed income securities | 70,924 | — | — | 70,924 |
| U.S. equity securities | 87,562 | — | — | 87,562 |
| International equity securities | 46,548 | — | — | 46,548 |
| Absolute return (1) | 11,671 | — | — | 11,671 |
| Commodities (2) | 5,870 | — | — | 5,870 |
| Common/collective trusts: | | | | |
| Fixed income securities | — | 14,840 | — | 14,840 |
| U.S. equity securities | — | 11,070 | — | 11,070 |
| Absolute return (1) | — | — | 844 | 844 |
| Real estate | — | — | 6,029 | 6,029 |
| Partnership/closely held investments: | | | | |
| Absolute return (1) | — | — | 15,794 | 15,794 |
| Private equity funds (3) | — | — | 1,561 | 1,561 |
| Total | $ 222,594 | $ 25,910 | $ 24,228 | $ 272,732 |

*(1) This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income, and (d) market neutral strategies.*

*(2) The fund primarily invests in derivatives linked to commodity indices to gain exposure to the commodity markets. The fund manager fully collateralizes these positions with debt securities.*

*(3) This category includes several private equity funds that invest primarily in U.S. companies.*

**The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2010 (dollars in thousands):**

| | Common/collective trusts | | Partnership/closely held investments | |
|---|---|---|---|---|
| | Absolute return | Real estate | Absolute return | Private equity funds |
| Balance, as of January 1, 2010 | $ 844 | $ 6,029 | $ 15,794 | $ 1,561 |
| Realized gains (losses) | (233) | 630 | — | (148) |
| Unrealized gains (losses) | (193) | (160) | 1,123 | (48) |
| Purchases (sales), net | (323) | (6,076) | — | (93) |
| Balance, as of December 31, 2010 | $ 95 | $ 423 | $ 16,917 | $ 1,272 |

**The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2009 (dollars in thousands):**

| | Common/collective trusts | | Partnership/closely held investments | |
|---|---|---|---|---|
| | Absolute return | Real estate | Absolute return | Private equity funds |
| Balance, as of January 1, 2009 | $ 2,351 | $ 11,987 | $ 13,983 | $ 1,316 |
| Realized gains (losses) | (415) | 520 | — | 3 |
| Unrealized gains (losses) | (21) | (4,310) | 1,811 | 223 |
| Purchases (sales), net | (1,071) | (2,168) | — | 19 |
| Balance, as of December 31, 2009 | $ 844 | $ 6,029 | $ 15,794 | $ 1,561 |

The market-related value of other postretirement plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 62 percent equity securities and 38 percent debt securities in 2010 and 2009.

The market-related value of other postretirement plan assets was determined as of December 31, 2010 and 2009.

**The following table discloses by level within the fair value hierarchy (refer to Note 20 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2010 at fair value (dollars in thousands):**

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Cash equivalents | $ 118 | $ — | $ — | $ 118 |
| Mutual funds: | | | | |
| Debt securities | 8,320 | — | — | 8,320 |
| U.S. equity securities | 6,986 | — | — | 6,986 |
| International equity securities | 5,572 | — | — | 5,572 |
| Debt securities | 37 | — | — | 37 |
| U.S. equity securities | 1,785 | — | — | 1,785 |
| International equity securities | 57 | — | — | 57 |
| Total | $ 22,875 | $ — | $ — | $ 22,875 |

**The following table discloses by level within the fair value hierarchy (refer to Note 20 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2009 at fair value (dollars in thousands):**

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Cash equivalents | $ 96 | $ — | $ — | $ 96 |
| Mutual funds: | | | | |
| Debt securities | 7,742 | — | — | 7,742 |
| U.S. equity securities | 5,927 | — | — | 5,927 |
| International equity securities | 5,077 | — | — | 5,077 |
| Debt securities | 25 | — | — | 25 |
| U.S. equity securities | 1,456 | — | — | 1,456 |
| International equity securities | 71 | — | — | 71 |
| Total | $ 20,394 | $ — | $ — | $ 20,394 |

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2010 by $5.2 million and the service and interest cost by $0.3 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2010 by $4.4 million and the service and interest cost by $0.2 million.

The Company and its most significant subsidiaries have salary deferral 401(k) plans that are defined contribution plans and cover substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The respective company matches a portion of the salary deferred by each participant according to the schedule in the respective plan.

**Employer matching contributions were as follows for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Employer 401(k) matching contributions | $ 5,405 | $ 4,667 | $ 4,829 |

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust.

**There were deferred compensation assets included in other property and investments-net and corresponding deferred compensation liabilities included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets of the following amounts as of December 31 (dollars in thousands):**

| | 2010 | 2009 |
|---|---|---|
| Deferred compensation assets and liabilities | $ 9,285 | $ 9,437 |

## NOTE 11. ACCOUNTING FOR INCOME TAXES

**Income tax expense consisted of the following for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Taxes currently provided | $ 13,423 | $ 32,470 | $ 1,464 |
| Deferred income tax expense (benefit) | 37,734 | 13,853 | 44,161 |
| Total income tax expense | $ 51,157 | $ 46,323 | $ 45,625 |

**A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2010, 2009 and 2008) applied to income before income taxes as set forth in the accompanying Consolidated Statements of Income is as follows for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Federal income taxes at statutory rates | $ 51,137 | $ 47,182 | $ 41,676 |
| Increase (decrease) in tax resulting from: | | | |
| Tax effect of regulatory treatment of utility plant differences | 2,761 | 1,858 | 2,260 |
| State income tax expense | 624 | 2,746 | 1,617 |
| Settlement of prior year tax returns and adjustment of tax reserves | (1,030) | (2,726) | 2,505 |
| Manufacturing deduction | (1,630) | (1,091) | (991) |
| Kettle Falls tax credit | — | (1,622) | (1,773) |
| Other | (705) | (24) | 331 |
| Total income tax expense | $ 51,157 | $ 46,323 | $ 45,625 |

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards.

**The total net deferred income tax liability consisted of the following as of December 31 (dollars in thousands):**

| | 2010 | 2009 |
|---|---|---|
| **Deferred income tax assets:** | | |
| Allowance for doubtful accounts | $ 12,556 | $ 11,872 |
| Reserves not currently deductible | 5,872 | 6,219 |
| Net operating loss from subsidiary acquisition | 6,495 | 7,106 |
| Deferred compensation | 3,877 | 4,880 |
| Unfunded benefit obligation | 54,195 | 41,089 |
| Utility energy commodity derivatives | 28,878 | 21,549 |
| Natural gas deferrals | 7,726 | 13,983 |
| Tax credits | 14,671 | 11,604 |
| Other | 23,226 | 15,203 |
| Total deferred income tax assets | $ 157,496 | $ 133,505 |
| **Deferred income tax liabilities:** | | |
| Intangible assets from subsidiary acquisition | $ 3,505 | $ 4,021 |
| Differences between book and tax basis of utility plant | 457,661 | 440,335 |
| Power deferrals | 8,747 | 9,720 |
| Regulatory asset for pensions and other postretirement benefits | 62,645 | 49,380 |
| Power exchange contract | 19,966 | 23,984 |
| Utility energy commodity derivatives | 28,880 | 21,549 |
| Demand side management programs | 4,184 | 7,808 |
| Loss on reacquired debt | 7,979 | 4,284 |
| Interest rate swaps | 333 | 4,342 |
| Settlement with Coeur d'Alene Tribe | 21,193 | 18,243 |
| Other | 9,055 | 10,032 |
| Total deferred income tax liabilities | 624,148 | 593,698 |
| Net deferred income tax liability | $ 466,652 | $ 460,193 |
| | | |
| Current deferred income tax asset | $ 28,822 | $ 34,473 |
| Long-term deferred income tax liability | 495,474 | 494,666 |
| Net deferred income tax liability | $ 466,652 | $ 460,193 |

As of December 31, 2010, the Company had $11.2 million of state tax credit carryforwards. State tax credits expire from 2015 to 2023. The Company recognizes the effect of state tax credits generated from utility plant as they are utilized.

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2007 and all issues were resolved related to these years. The IRS has not examined the Company's 2008 or 2009 federal income tax returns. However, an estimate of the range of any such possible change cannot be made at this time. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

On September 10, 2008, the Company entered into a Settlement Agreement with the Appeals Division of the IRS that resolved all items noted during their audit of the Company's 2001 through 2003 tax years, including, among other things, indirect overhead expenses. The agreement was reviewed and approved by the Joint Committee on Taxation, and a settlement payment was received in December 2008. The original IRS disallowance and the Company's appeal of the indirect overhead issue caused a delay in associated tax refunds for net operating losses that were carried back to several earlier years. The final settlement with the IRS freed up the refund years and set the amount owed for the 2001-2003 tax years. The net result was a refund to the Company of $14.7 million, plus interest of $5.7 million which has been included in other income — net in the Consolidated Statements of Income.

**The following table presents the activity in the liability for unrecognized tax benefits during the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Balance as of the beginning of the year | $ — | $ — | $ 22,619 |
| Settlements with the IRS | — | — | (22,619) |
| Balance as of the end of the year | $ — | $ — | $ — |

The Company did not incur any penalties on income tax positions in 2010, 2009 or 2008. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

**The Company had net regulatory assets related to the probable recovery of certain deferred income tax liabilities from customers through future rates as of December 31 (dollars in thousands):**

| | 2010 | 2009 |
|---|---|---|
| Regulatory assets for deferred income taxes | $ 90,025 | $ 97,945 |

## NOTE 12. ENERGY PURCHASE CONTRACTS

Avista Utilities has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The termination dates of the contracts range from one month to the year 2055.

**Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in utility resource costs in the Consolidated Statements of Income, were as follows for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Utility power resources | $ 649,408 | $ 704,886 | $ 951,401 |

**The following table details Avista Utilities' future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Power resources | $ 217,093 | $ 159,409 | $ 119,250 | $ 105,974 | $ 97,163 | $ 666,752 | $ 1,365,641 |
| Natural gas resources | 138,917 | 100,658 | 83,908 | 65,192 | 56,514 | 631,946 | 1,077,135 |
| Total | $ 356,010 | $ 260,067 | $ 203,158 | $ 171,166 | $ 153,677 | $ 1,298,698 | $ 2,442,776 |

These energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail electric and natural gas customers' energy requirements. As a result, these costs are recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

In addition, Avista Utilities has operational agreements, settlements and other contractual obligations for its generation, transmission and distribution facilities. The expenses associated with these agreements are reflected as other operating expenses in the Consolidated Statements of Income.

**The following table details future contractual commitments for these agreements (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Contractual obligations | $ 21,551 | $ 23,307 | $ 22,643 | $ 23,100 | $ 24,525 | $ 252,015 | $ 367,141 |

Avista Utilities has fixed contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Utilities has no investment in the PUD generating facilities, the fixed contracts obligate Avista Utilities to pay certain minimum amounts (based in part on the debt service requirements of the PUD) whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Consolidated Statements of Income.

**Expenses under these PUD contracts were as follows for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| PUD contract costs | $ 8,287 | $ 12,633 | $ 14,875 |

**Information as of December 31, 2010 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):**

| | Output | Kilowatt Capability | Annual Costs (1) | Company's Current Share of Debt Service Costs (1) | Bonds Outstanding | Expiration Date |
|---|---|---|---|---|---|---|
| Chelan County PUD: | | | | | | |
| Rocky Reach Project | 2.9% | 37,000 | $ 2,172 | $ 1,013 | $ 436 | 2011 |
| Douglas County PUD: | | | | | | |
| Wells Project | 3.3% | 28,000 | 1,734 | 698 | 3,773 | 2018 |
| Grant County PUD: | | | | | | |
| Priest Rapids and Wanapum Projects | 3.3% | 65,800 | 4,381 | 1,803 | 19,537 | 2055 |
| Totals | | 130,800 | $ 8,287 | $ 3,514 | $ 23,746 | |

*(1) The annual costs will change in proportion to the percentage of output allocated to Avista Utilities in a particular year. Amounts represent the operating costs for 2010. Debt service costs are included in annual costs.*

**The estimated aggregate amounts of required minimum payments (Avista Utilities' share of existing debt service costs) under these PUD contracts are as follows (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Minimum payments | $ 3,026 | $ 2,590 | $ 2,585 | $ 2,557 | $ 2,447 | $ 28,026 | $ 41,231 |

In addition, Avista Utilities will be required to pay its proportionate share of the variable operating expenses of these projects.

## NOTE 13. ACCOUNTS RECEIVABLE FINANCING FACILITY

On December 30, 2010, Avista Corp., Avista Receivables Corporation (ARC), Bank of America, N.A. and Ranger Funding Company, LLC terminated a Receivables Purchase Agreement at the direction of the Company. ARC is a wholly owned, bankruptcy-remote subsidiary of the Company formed in 1997 for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. The Company elected to terminate the Receivables Purchase Agreement prior to its March 11, 2011 expiration date based on the Company's forecasted liquidity needs. The Receivables Purchase Agreement was originally entered into on May 29, 2002 (and has been renewed on an annual basis) and provided the Company with funds for general corporate needs. Under the Receivables Purchase Agreement, the Company could borrow up to $50.0 million based on calculations of eligible receivables. The Company did not borrow any funds under this revolving agreement in 2010.

## NOTE 14. SHORT-TERM BORROWINGS

At December 31, 2010, Avista Corp. had a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company could borrow or request the issuance of letters of credit in any combination up to $320.0 million. Additionally, the Company had a committed line of credit agreement with various banks in the total amount of $75.0 million with an expiration date of April 5, 2011.

In February 2011, Avista Corp. entered into a new committed line of credit in the total amount of $400.0 million with an expiration date of February 2015 that replaced its $320.0 million and $75.0 million committed lines of credit.

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

The committed line of credit agreements contain customary covenants and default provisions. The $320.0 million and $75.0 million credit agreements had a covenant that required the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2010, the Company was in compliance with this covenant. The new $400.0 million committed line of credit does not have this covenant. The $320.0 million and $75.0 million credit agreements also had a covenant which did not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 70 percent at any time. As of December 31, 2010, the Company was in compliance with this covenant. Under the new $400.0 million committed line of credit, this ratio must not be greater than 65 percent at any time.

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Balance outstanding at end of period | $ 110,000 | $ 87,000 | $ 250,000 |
| Letters of credit outstanding at end of period | $ 27,126 | $ 28,448 | $ 24,325 |
| Average interest rate at end of period | 0.57% | 0.59% | 0.81% |

**Advantage IQ**

As of December 31, 2010, Advantage IQ had a $15.0 million committed credit agreement with an expiration date of February 2011. Advantage IQ may elect to increase the credit facility to $25.0 million under the same agreement. The credit agreement is secured by substantially all of Advantage IQ's assets. In February 2011, Advantage IQ extended the expiration date of this credit facility to May 2011.

**Balances outstanding and interest rates of borrowings under Advantage IQ's credit agreement were as follows as of and for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Balance outstanding at end of period | $ — | $ 5,700 | $ 2,200 |
| Average interest rate at end of period | — | 1.23% | 2.08% |

## NOTE 15. LONG-TERM DEBT

**The following details long-term debt outstanding as of December 31 (dollars in thousands):**

| Maturity Year | Description | Interest Rate | 2010 | 2009 |
|---|---|---|---|---|
| 2010 | Secured Medium-Term Notes | 6.67% — 8.02% | $ — | $ 35,000 |
| 2012 | Secured Medium-Term Notes | 7.37% | 7,000 | 7,000 |
| 2013 | First Mortgage Bonds (1) | 6.13% | — | 45,000 |
| 2013 | First Mortgage Bonds (1) | 7.25% | — | 30,000 |
| 2013 | First Mortgage Bonds (2) | 1.68% | 50,000 | — |
| 2018 | First Mortgage Bonds | 5.95% | 250,000 | 250,000 |
| 2018 | Secured Medium-Term Notes | 7.39% — 7.45% | 22,500 | 22,500 |
| 2019 | First Mortgage Bonds | 5.45% | 90,000 | 90,000 |
| 2020 | First Mortgage Bonds (1) | 3.89% | 52,000 | — |
| 2022 | First Mortgage Bonds | 5.13% | 250,000 | 250,000 |
| 2023 | Secured Medium-Term Notes | 7.18% — 7.54% | 13,500 | 13,500 |
| 2028 | Secured Medium-Term Notes | 6.37% | 25,000 | 25,000 |
| 2032 | Secured Pollution Control Bonds (3) | (3) | 66,700 | 66,700 |
| 2034 | Secured Pollution Control Bonds (4) | (4) | 17,000 | 17,000 |
| 2035 | First Mortgage Bonds | 6.25% | 150,000 | 150,000 |
| 2037 | First Mortgage Bonds | 5.70% | 150,000 | 150,000 |
| 2040 | First Mortgage Bonds (1) | 5.55% | 35,000 | — |
| | Total secured long-term debt | | 1,178,700 | 1,151,700 |
| 2023 | Unsecured Pollution Control Bonds | 6.00% | 4,100 | 4,100 |
| | Other long-term debt and capital leases | | 5,500 | 3,018 |
| | Settled interest rate swaps | | (951) | (1,844) |
| | Unamortized debt discount | | (1,792) | (1,936) |
| | Total | | 1,185,557 | 1,155,038 |
| | Secured Pollution Control Bonds held by Avista Corporation (3)(4) | | (83,700) | (83,700) |
| | Current portion of long-term debt | | (358) | (35,189) |
| | Total long-term debt | | $ 1,101,499 | $ 1,036,149 |

(1) *In December 2010, Avista Corp. issued $52.0 million of 3.89 percent First Mortgage Bonds due in 2020 and $35.0 million of 5.55 percent First Mortgage Bonds due in 2040. The total net proceeds from the sale of the new bonds of $86.6 million (net of placement agent fees and before Avista Corp.'s expenses) were used to redeem $45.0 million of 6.125 percent First Mortgage Bonds due in December 2013 and $30.0 million of 7.25 percent First Mortgage Bonds due in September 2013. These First Mortgage Bonds were redeemed at par plus a make-whole redemption premium of $10.7 million. In accordance with regulatory accounting practices, the make-whole redemption premium will be amortized over the life of the new debt issued.*

(2) *In December 2010, Avista Corp. issued $50.0 million of 1.68 percent First Mortgage Bonds (Bonds) due in 2013. The net proceeds from the issuance of the Bonds of $49.8 million (net of placement agent fees and before Avista Corp.'s expenses) were used to repay a portion of the borrowings outstanding under the Company's committed line of credit.*

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

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

**The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 16) (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Debt maturities | $ — | $ 7,000 | $ 50,000 | $ — | $ — | $ 1,093,647 | $ 1,150,647 |

Substantially all utility properties owned by the Company are subject to the lien of the Company's mortgage indenture. Under the Mortgage and Deed of Trust securing the Company's First Mortgage Bonds (including Secured Medium-Term Notes), the Company may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of: 1) 70 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 2) an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or 3) deposit of cash. However, the Company may not issue any additional First Mortgage Bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the Company's "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, 2010, property additions and retired bonds would have allowed the Company to issue $795.3 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2010, the net earnings test would limit the principal amount of additional bonds the Company could issue to $758.8 million.

See Note 14 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its committed lines of credit agreements.

**Nonrecourse Long-Term Debt**

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

**The following table details future nonrecourse long-term debt maturities (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Debt maturities | $ 12,463 | $ 13,668 | $ 14,965 | $ 16,407 | $ 1,431 | $ — | $ 58,934 |

## NOTE 16. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

**The distribution rates paid were as follows during the years ended December 31:**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Low distribution rate | 1.13% | 1.22% | 3.06% |
| High distribution rate | 1.41% | 3.06% | 6.00% |
| Distribution rate at the end of the year | 1.17% | 1.22% | 3.06% |

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II on or after June 1, 2007 and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed. The Company does not include these capital trusts in its consolidated financial statements. As such, the sole assets of the capital trusts are $51.5 million of junior subordinated deferrable interest debentures of Avista Corp., which are reflected on the Consolidated Balance Sheets. Interest expense to affiliated trusts in the Consolidated Statements of Income represents interest expense on these debentures.

## NOTE 17. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from one to forty-five years.

**Rental expense under operating leases was as follows for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Rental expense | $ 6,080 | $ 5,624 | $ 4,761 |

**Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2010 were as follows (dollars in thousands):**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Minimum payments required | $ 4,501 | $ 4,125 | $ 4,091 | $ 4,153 | $ 1,857 | $ 6,059 | $ 24,786 |

## NOTE 18. GUARANTEES

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities issued by its affiliate, Avista Capital II, to the extent that this entity has funds available for such payments from its debt securities.

The output from the Lancaster Plant was contracted to Avista Turbine Power, Inc. (ATP), an affiliate of Avista Energy, through 2026 under a power purchase agreement (PPA). The majority of the rights and obligations of this PPA were conveyed to Shell Energy through the end of 2009. Beginning in January 2010, the rights and obligations under the PPA were conveyed to Avista Corp. Effective December 1, 2010, the PPA was assigned to Avista Corp. Prior to the assignment, Avista Corp. had provided Rathdrum Power LLC, the owner of the Lancaster Plant, a guarantee under which Avista Corp. has guaranteed ATP's performance under the PPA. This guarantee was terminated in connection with the assignment of the PPA to Avista Corp.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 24), existing litigation, tax liabilities, and matters related to storage rights at Jackson Prairie. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. The Guaranty will terminate April 30, 2011 except for claims made prior to termination. The Company has not recorded any liability related to this guaranty.

## NOTE 19. PREFERRED STOCK-CUMULATIVE (SUBJECT TO MANDATORY REDEMPTION)

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2010 and 2009.

## NOTE 20. FAIR VALUE

Fair value represents the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The carrying values of cash and cash equivalents, accounts and notes receivable, accounts payable and short-term borrowings are reasonable estimates of their fair values. Long-term debt (including current portion, but excluding capital leases), nonrecourse long-term debt and long-term debt to affiliated trusts are reported at carrying value on the Consolidated Balance Sheets.

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

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | Carrying Value | Estimated Fair Value | Carrying Value | Estimated Fair Value |
| Long-term debt | $ 1,099,100 | $ 1,139,765 | $ 1,072,100 | $ 1,079,857 |
| Nonrecourse long-term debt | 58,934 | 64,795 | — | — |
| Long-term debt to affiliated trusts | 51,547 | 37,114 | 51,547 | 43,534 |

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

Energy commodity derivative assets and liabilities, funds held for customers, deferred compensation assets, as well as derivatives related to interest rate swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Consolidated Balance Sheets. U.S. GAAP defines a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy are defined as follows:

- **Level 1** — Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

- **Level 2** — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

- **Level 3** — Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

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

**The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheets as of December 31, 2010 and 2009 at fair value on a recurring basis (dollars in thousands):**

| | Level 1 | Level 2 | Level 3 | Counterparty Netting [1] | Total |
|---|---|---|---|---|---|
| **December 31, 2010** | | | | | |
| **Assets:** | | | | | |
| Energy commodity derivatives | $ — | $ 15,124 | $ 19,739 | $ (17,010) | $ 17,853 |
| Interest rate swaps | — | 127 | — | — | 127 |
| Foreign currency derivatives | — | 116 | — | — | 116 |
| Funds held for customers [2] | 100,543 | — | — | — | 100,543 |
| Funds held in trust account of Spokane Energy | 1,600 | — | — | — | 1,600 |
| Deferred compensation assets: | | | | | |
| Fixed income securities [3] | 1,854 | — | — | — | 1,854 |
| Equity securities [3] | 6,211 | — | — | — | 6,211 |
| Total | $ 110,208 | $ 15,367 | $ 19,739 | $ (17,010) | $ 128,304 |
| **Liabilities:** | | | | | |
| Energy commodity derivatives | $ — | $ 93,198 | $ 6,280 | $ (17,010) | $ 82,468 |
| Interest rate swaps | — | 53 | — | — | 53 |
| Total | $ — | $ 93,251 | $ 6,280 | $ (17,010) | $ 82,521 |
| **December 31, 2009** | | | | | |
| **Assets:** | | | | | |
| Energy commodity derivatives | $ — | $ 11,898 | $ 57,276 | $ (15,934) | $ 53,240 |
| Funds held for customers [2] | 51,128 | — | — | — | 51,128 |
| Deferred compensation assets: | | | | | |
| Fixed income securities [3] | 2,011 | — | — | — | 2,011 |
| Equity securities [3] | 5,863 | — | — | — | 5,863 |
| Total | $ 59,002 | $ 11,898 | $ 57,276 | $ (15,934) | $ 112,242 |
| **Liabilities:** | | | | | |
| Energy commodity derivatives | $ — | $ 27,086 | $ 7,806 | $ (15,934) | $ 18,958 |
| Foreign currency derivatives | — | 50 | — | — | 50 |
| Total | $ — | $ 27,136 | $ 7,806 | $ (15,934) | $ 19,008 |

*(1) The Company is permitted to net derivative assets and derivative liabilities when a legally enforceable master netting agreement exists.*

*(2) Represents amounts held in money market funds.*

*(3) These assets are trading securities.*

Avista Utilities enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of Avista Utilities' management of loads and resources and certain contracts are considered derivative instruments. The difference between the amount of derivative assets and liabilities disclosed in respective levels and the amount of derivative assets and liabilities disclosed on the Consolidated Balance Sheets is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using broker quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using broker quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2. The Company also has certain contracts that, primarily due to the length of the respective contract, require the use of internally developed forward price estimates, which include significant inputs that may not be observable or corroborated in the market. These derivative contracts are included in Level 3. Refer to Note 6 for further discussion of the Company's energy commodity derivative assets and liabilities.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an Executive Deferral Plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $1.2 million as of December 31, 2010 and $1.6 million as of December 31, 2009.

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

| | Assets | | | Liabilities | | |
|---|---|---|---|---|---|---|
| | 2010 | 2009 | 2008 | 2010 | 2009 | 2008 |
| Balance as of January 1 | $ 57,276 | $ 68,047 | $ 98,943 | $ (7,806) | $ (16,085) | $ (36,506) |
| Total gains or losses (realized/unrealized): | | | | | | |
| Included in net income | — | — | — | — | — | — |
| Included in other comprehensive income | — | — | — | — | — | — |
| Included in regulatory assets/liabilities (1) | (34,943) | (7,202) | (22,586) | 1,209 | 7,747 | 18,715 |
| Purchases, issuances, and settlements, net | (2,594) | (3,569) | (8,310) | 317 | 532 | 1,706 |
| Transfers to other categories | — | — | — | — | — | — |
| Ending balance as of December 31 | $ 19,739 | $ 57,276 | $ 68,047 | $ (6,280) | $ (7,806) | $ (16,085) |

*(1) The WUTC and the IPUC issued accounting orders authorizing Avista Utilities to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Utilities 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.*

## NOTE 21. COMMON STOCK

The Company has a Direct Stock Purchase and Dividend Reinvestment Plan under which the Company's shareholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's common stock at current market value. Shares issued under this plan in 2010, 2009 and 2008 are disclosed in the Consolidated Statements of Equity and Redeemable Noncontrolling Interests.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock contained in the Company's Articles of Incorporation, as amended.

In August 2010, the Company entered into an amended and restated sales agency agreement with a sales agent to issue up to 3,087,500 shares of its common stock from time to time. The Company originally entered into a sales agency agreement to issue up to 1,250,000 shares of its common stock in December 2009. The Company issued shares in 2008 under a previous agreement.

**Shares issued under sales agency agreements were as follows in the years ended December 31:**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Shares issued under sales agency agreement | 2,054,110 | — | 750,000 |

## NOTE 22. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Numerator:** | | | |
| Net income attributable to Avista Corporation | $ 92,425 | $ 87,071 | $ 73,620 |
| Subsidiary earnings adjustment for dilutive securities | (226) | (114) | (249) |
| Adjusted net income attributable to Avista Corporation for computation of diluted earnings per common share | $ 92,199 | $ 86,957 | $ 73,371 |
| **Denominator:** | | | |
| Weighted-average number of common shares outstanding-basic | 55,595 | 54,694 | 53,637 |
| Effect of dilutive securities: | | | |
| Performance and restricted stock awards | 157 | 163 | 213 |
| Stock options | 72 | 85 | 178 |
| Weighted-average number of common shares outstanding-diluted | 55,824 | 54,942 | 54,028 |
| Potential shares excluded in calculation | — | 218 | 251 |
| **Earnings per common share attributable to Avista Corporation:** | | | |
| Basic | $ 1.66 | $ 1.59 | $ 1.37 |
| Diluted | $ 1.65 | $ 1.58 | $ 1.36 |

Certain stock options were excluded from the calculation because they were antidilutive based on the fact that the exercise price of the stock options was higher than the average market price of Avista Corp. common stock during the respective period.

## NOTE 23. STOCK COMPENSATION PLANS

### 1998 Plan

In 1998, the Company adopted, and shareholders approved, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, officers and non-employee directors of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. In May 2010, the Company's shareholders approved an additional 1 million shares of Company common stock to be made available for grant under this plan. However, as of December 31, 2010, the Company has not received approvals from regulatory agencies to add these 1 million share to the 1998 plan. The Company has available a maximum of 3.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2010, 0.5 million shares were remaining for grant under this plan.

### 2000 Plan

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of non-employee directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan. However, the Company currently does not plan to issue any further options or securities under the 2000 Plan. As of December 31, 2010, 1.9 million shares were remaining for grant under this plan.

### Stock Compensation

The Company records compensation cost relating to share-based payment transactions in the financial statements based on the fair value of the equity or liability instruments issued.

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

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Stock-based compensation expense | $ 4,916 | $ 2,906 | $ 3,001 |
| Income tax benefits | 1,720 | 1,017 | 1,050 |

### Stock Options

**The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Number of shares under stock options: | | | |
| Options outstanding at beginning of year | 523,973 | 748,673 | 1,411,911 |
| Options granted | — | — | — |
| Options exercised | (101,649) | (200,225) | (582,238) |
| Options canceled | (220,650) | (24,475) | (81,000) |
| Options outstanding and exercisable at end of year | 201,674 | 523,973 | 748,673 |
| Weighted average exercise price: | | | |
| Options exercised | $ 11.51 | $ 13.83 | $ 13.91 |
| Options canceled | $ 22.60 | $ 22.69 | $ 21.70 |
| Options outstanding and exercisable at end of year | $ 11.53 | $ 16.30 | $ 15.85 |
| Cash received from options exercised (in thousands) | $ 2,179 | $ 2,770 | $ 8,097 |
| Intrinsic value of options exercised (in thousands) | $ 1,006 | $ 1,180 | $ 4,248 |
| Intrinsic value of options outstanding (in thousands) | $ 2,217 | $ 2,774 | $ 2,643 |

**Information for options outstanding and exercisable as of December 31, 2010 is as follows:**

| Range of Exercise Prices | Number of Shares | Weighted Average Exercise Price | Weighted Average Remaining Life (in years) |
|---|---|---|---|
| $10.17 — $12.41 | 186,674 | $ 10.97 | 1.4 |
| $15.88 — $19.34 | 6,000 | 15.88 | 1.4 |
| $20.11 — $23.00 | 9,000 | 20.11 | 0.4 |
| Total | 201,674 | $ 11.53 | 1.4 |

As of December 31, 2010 and 2009, the Company's stock options were fully vested and expensed.

### Restricted Shares

Restricted shares vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the CEO's restricted shares to vest. During the vesting period, employees are entitled to dividend equivalents which are paid when dividends on the Company's common stock are declared. Restricted stock is valued at the close of market of the Company's common stock on the grant date. The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2010 was 1.3 years.

**The following table summarizes restricted stock activity for the years ended December 31:**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Unvested shares at beginning of year | 71,904 | 55,939 | 28,137 |
| Shares granted | 43,800 | 44,400 | 43,400 |
| Shares cancelled | — | (10,000) | (1,230) |
| Shares vested | (31,570) | (18,435) | (14,368) |
| Unvested shares at end of year | 84,134 | 71,904 | 55,939 |
| Weighted average fair value at grant date | $ 19.80 | $ 18.18 | $ 20.05 |
| Unrecognized compensation expense at end of year (in thousands) | $ 735 | $ 668 | $ 691 |
| Intrinsic value, unvested shares at end of year (in thousands) | $ 1,895 | $ 1,552 | $ 1,084 |
| Intrinsic value, shares vested during the year (in thousands) | $ 682 | $ 345 | $ 293 |

### Performance Shares

Performance share grants have vesting periods of three years. Performance awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific performance conditions. Based on the attainment of the performance condition, the amount of cash paid or common stock issued will range from 0 to 150 percent of the performance shares granted depending on the change in the value of the Company's common stock relative to an external benchmark. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest.

Performance share awards entitle the grantee to shares of common stock or cash payable once the service condition is satisfied. Based on attainment of the performance condition, grantees may receive 0 to 150 percent of the original shares granted. The performance condition used is the Company's Total Shareholder Return performance over a three-year period as compared against other utilities; this is considered a market-based condition. Performance shares may be settled in common stock or cash at the discretion of the Company. Historically, the Company has settled these awards through issuance of stock and intends to continue this practice. These awards vest at the end of the three-year period. Performance shares are equity awards with a market-based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is rendered, regardless of when, if ever, the market condition is satisfied.

The Company measures (at the grant date) the estimated fair value of performance shares granted. The fair value of each performance share award was estimated on the date of grant using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to a peer group. Expected volatility was based on the historical volatility of Avista Corp. common stock over a three-year period. The expected term of the performance shares is three years based on the performance cycle. The risk-free interest rate was based on the U.S. Treasury yield at the time of grant. The compensation expense on these awards will only be adjusted for changes in forfeitures.

**The following summarizes the weighted average assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Risk-free interest rate | 1.4% | 1.3% | 2.2% |
| Expected life, in years | 3 | 3 | 3 |
| Expected volatility | 27.8% | 25.8% | 20.2% |
| Dividend yield | 4.6% | 3.6% | 2.8% |
| Weighted average grant date fair value (per share) | $ 15.30 | $ 17.22 | $ 16.96 |

The fair value includes both performance shares and dividend equivalent rights.

**The following summarizes performance share activity:**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Opening balance of unvested performance shares | 300,601 | 252,923 | 207,841 |
| Performance shares granted | 168,700 | 163,900 | 170,100 |
| Performance shares canceled | — | (43,758) | (5,239) |
| Performance shares vested | (143,601) | (72,464) | (119,779) |
| Ending balance of unvested performance shares | 325,700 | 300,601 | 252,923 |
| Intrinsic value of unvested performance shares (in thousands) | $ 7,335 | $ 6,490 | $ 4,902 |
| Unrecognized compensation expense (in thousands) | $ 2,330 | $ 2,453 | $ 2,227 |

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2010 was 1.5 years. Unrecognized compensation expense as of December 31, 2010 will be recognized during 2011 and 2012.

**The following summarizes the impact of the market condition on the vested performance shares:**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Performance shares vested | 143,601 | 72,464 | 119,779 |
| Impact of market condition on shares vested | 21,540 | (72,464) | 21,560 |
| Shares of common stock earned | 165,141 | — | 141,339 |
| Intrinsic value of common stock earned (in thousands) | $ 3,719 | $ — | $ 2,739 |

Shares earned under this plan are distributed to participants in the quarter following vesting.

Awards outstanding under the performance share grants include a dividend component that is paid in cash. This component of the performance share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, and the change in the value of the Company's common stock relative to an external benchmark. Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2010 and 2009, the Company had recognized compensation expense and a liability of $0.9 million and $0.4 million related to the dividend component of performance share grants.

**Advantage IQ**

Advantage IQ has an employee stock incentive plan under which certain employees of Advantage IQ may be granted options to purchase shares of Advantage IQ at prices no less than the estimated fair value on the date of grant. Options outstanding under this plan generally vest over periods of four years from the date granted and terminate ten years from the date granted. Unrecognized compensation expense for stock based awards at Advantage IQ was $2.3 million as of December 31, 2010, which will be expensed during 2011 through 2014.

In 2007, Advantage IQ amended its employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Advantage IQ providing the shares are held for a minimum of six months. In 2009, Advantage IQ amended its employee stock incentive plan to make this put feature optional for future stock option grants. Stock is reacquired at fair market value at the date of reacquisition. Additionally, there was redeemable noncontrolling interests related to the Cadence Network acquisition, as the previous owners can exercise a right to put their stock back to Advantage IQ (refer to Note 5 for further information).

**The following amounts of common stock were repurchased from Advantage IQ employees during the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Stock repurchased from Advantage IQ employees | $ 2,593 | $ 4,725 | $ 6,624 |

## NOTE 24. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. After consultation with legal counsel, the Company accrues 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. For matters that affect Avista Utilities' operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

### Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp. doing business as Avista Utilities, Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Utilities or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Utilities or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). The Attorney General of the State of California (California AG), the California Electricity Oversight Board, California Parties and the City of Tacoma, Washington challenged the FERC's decisions approving the Agreement in Resolution, which are now pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

In May 2004, the FERC provided notice that Avista Energy was no longer subject to an investigation reviewing certain bids above $250 per MW in the short-term energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) from May 1, 2000 to October 2, 2000 (Bidding Investigation). That matter is also pending before the Ninth Circuit, after the California AG, Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE) and the California Public Utilities Commission (CPUC) filed petitions for review in 2005.

Based on the FERC's order approving the Agreement in Resolution and the FERC's denial of rehearing requests, the Company does not expect that this proceeding will have any material adverse effect on its financial condition, results of operations or cash flows. Furthermore, based on information currently known to the Company regarding the Bidding Investigation and the fact that the FERC Staff did not find any evidence of manipulative behavior, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

### California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In June 2009, the FERC reversed, in part, its previous decision and ordered a compliance filing requiring an adjustment to the return on investment component of Avista Energy's cost filing. That compliance filing was made in July 2009. In March 2010, the California AG, the CPUC, PG&E, and SCE filed a protest and comments on Avista Energy's compliance filing. In April 2010, Avista Energy filed a response and corrected a technical error from its July 2009 filing. The correction increased its cost filing claim. The California AG, CPUC, PG&E and SCE filed an answer and protest to this filing in April 2010, which Avista Energy answered in June 2010. In July 2010, the same parties again opposed Avista Energy's cost filing, and Avista Energy answered that protest. The revised compliance filing is pending before the FERC.

The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In April 2010 and May 2010, the CalISO and CalPX, respectively, filed updated compliance reports concerning preparatory re-run activity. The CalPX filing requested guidance from the FERC on issues related to completing the final determination of "who owes what to whom." The CalPX supplemented its compliance filing in October 2010. In June 2010, Avista Energy filed comments with the FERC asking the FERC to assist the parties in bringing this matter to a close by expeditiously: 1) approving the compliance filings made by the CalISO and the CalPX; 2) ruling on the outstanding issues presented by the CalPX; and 3) setting milestones for next steps regarding the final compliance filing.

In July 2010, the CalISO filed its 45th status report on the California recalculation process confirming that the calculations related to fuel cost allowance offsets and emission offsets are complete, and identifying several open issues related to the refund rerun calculations that need to be resolved by the FERC. The CalISO states that it will need to revise certain calculations related to cost-recovery offsets and interest calculations. In addition, the CalISO stated that it is in the process of making adjustments to the CalISO data to remove refunds associated with sales made by non-jurisdictional entities. The CalISO also says that it will need to work with parties to the various global settlements to make appropriate adjustments to the CalISO's data in order to properly reflect those adjustments. In a March 2010 filing, the CalISO stated that it does not intend to make any compliance filing until, *inter alia*, the FERC resolves issues related to the Ninth Circuit's remand regarding possible remedies for alleged tariff violations pursuant to Federal Power Act (FPA) section 309, prior to the refund effective date in this proceeding (discussed below).

The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX. As a result, Avista Energy has not been paid for all of its energy sales during the Refund Period. Those funds are now in escrow accounts and will not be released until the FERC issues an order directing such release in the California refund proceeding. As of December 31, 2010, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from the defaulting parties.

Many of the orders that the FERC has issued in the California refund proceedings were appealed to the Ninth Circuit. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round was limited to three issues: (1) which parties are subject to the FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the FPA; (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit.

In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California refund proceeding. In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 refund proceeding, but remanded to the FERC its decision not to consider an FPA section 309 remedy for tariff violations prior to that date. Petitions for rehearing were denied in April 2009. In July 2009, Avista Energy and Avista Utilities filed a motion at the FERC, asking that the companies be dismissed from any further proceedings arising under section 309 pursuant to the remand. The filing pointed out that section 309 relief is based on tariff violations of the seller, and as to Avista Energy and Avista Utilities, these allegations had already been fully adjudicated in the proceeding that gave rise to the Agreement in Resolution, discussed above. There, the FERC absolved both companies of all allegations of market manipulation or wrongdoing that would justify or permit FPA sections 206 or 309 remedies during 2000 and 2001. In November 2009, the FERC issued an order establishing an evidentiary hearing before an administrative law judge to address the issues remanded by the Ninth Circuit without addressing the Company's pending motion. In December 2009, the Company again brought the issue to the FERC's attention but its motion remains pending, as do a number of rehearing requests regarding the November 2009 hearing order. In September 2010, the FERC issued a "Supplemental Order Soliciting Comments" on the scope of the hearing. The Company responded in filings made on September 22, 2010 and October 6, 2010, and the parties are awaiting further rulings by the FERC before the hearing commences.

Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent of the Company's liability, if any. However, based on information currently known, the Company does not expect that the refunds ultimately ordered for the Refund Period will have a material adverse effect on its financial condition, results of operations or cash flows. This is primarily due to the fact that the FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company.

**Pacific Northwest Refund Proceeding**

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased by the California Department of Water Resources (CERS) in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. Requests by various parties for rehearing on this ruling were denied in April 2009.

In May 2009, the California AG filed a complaint against both Avista Energy and Avista Utilities seeking refunds on sales made to CERS during the period January 18, 2001 to June 20, 2001 under section 309 of the FPA (the Brown Complaint). The sales at issue are limited in scope and are duplicative of claims already at issue in the Pacific Northwest proceeding, discussed above. In August 2009, the City of Tacoma and the Port of Seattle filed a motion asking the FERC to summarily re-price sales of energy in the Pacific Northwest during 2000 and 2001. In October 2009, Avista Corp. filed, as part of the Transaction Finality Group, an answer to that motion and, in addition, made its own recommendations for further proceedings in this docket. Those pleadings are pending before the FERC.

Both Avista Utilities and Avista Energy were buyers and sellers of energy in the Pacific Northwest energy market during the period between December 25, 2000 and June 20, 2001 and, if refunds were ordered by the FERC, could be liable to make payments, but also could be entitled to receive refunds from other FERC-jurisdictional entities. The opportunity to make claims against entities not subject to the FERC's jurisdiction may be limited based on existing law. The Company cannot predict the outcome of this proceeding or the amount of any refunds that Avista Utilities or Avista Energy could be ordered to make or could be entitled to receive. Therefore, the Company cannot predict the potential impact the outcome of this matter could ultimately have on the Company's results of operations, financial condition or cash flows.

**California Attorney General Complaint (the "Lockyer Complaint")**

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the California AG that alleged violations of the FPA by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's adoption and implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint but directing sellers to re-file certain transaction summaries. It was not clear that Avista Corp. and its subsidiaries were subject to this directive but the Company took the conservative approach and re-filed certain transaction summaries in June and July of 2002. In September 2004, the Ninth Circuit upheld the FERC's market-based rate authority, but held that the FERC erred in ruling that it lacked authority to order refunds for violations of its reporting requirement. The Court remanded the case for further proceedings, but did not order any refunds, leaving it to the FERC to consider appropriate remedial options.

In March 2008, the FERC issued an order establishing a trial-type hearing to address "whether any individual public utility seller's violation of the FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period." Purchasers in the California markets will be allowed to present evidence that "any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable." In particular, the parties were directed to address whether the seller at any point reached a 20 percent generation market share threshold, and if the seller did reach a 20 percent market share, whether other factors were present to indicate that the seller did not have the ability to exercise market power. The California AG, CPUC, PG&E, and SCE filed their testimony in July 2009. Avista Utilities and Avista Energy's answering testimony was filed in September 2009. On the same day, the FERC staff filed its answering testimony taking the position that, using the test the FERC directed to be applied in this proceeding, neither Avista Utilities nor Avista Energy had market power for the period in question. Cross answering testimony and rebuttal testimony were filed in November 2009. In January 2010, Avista Utilities and Avista Energy filed a motion for summary disposition, as did other parties to the proceeding. In March 2010, the Presiding Administrative Law Judge (ALJ) granted the motions for summary disposition and found that a hearing was "unnecessary" because the California AG, CPUC, PG&E and SCE "failed to apply the appropriate test to determine market power during the relevant time period." The judge determined that "[w]ithout a proper showing of market power, the California Parties failed to establish a prima facie case." Briefs on exceptions were filed in April 2010 and briefs opposing exceptions were filed in May 2010.

Based on information currently known to the Company's management, the fact that neither Avista Utilities nor Avista Energy ever reached a 20 percent generation market share during 2000 or 2001 and the ALJ's granting of Avista Utilities and Avista Energy's summary disposition motion, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

**Colstrip Generating Project Complaint**

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs allege that the holding ponds and remediation activities have adversely impacted their property. They allege contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also seek punitive damages, attorney's fees, an order by the court to remove certain ponds, and the forfeiture of profits earned from the generation of Colstrip. In September 2010, the owners of Colstrip filed a motion with the court to enforce a settlement agreement that would resolve all issues between the parties. Under the settlement, Avista Corp.'s portion of payment (which was accrued in the second quarter of 2010) to the plaintiffs was not material to its financial condition, results of operations or cash flows. The plaintiffs have indicated that they will contest the existence of any settlement, and will file a response to the motion, with the matter to be decided by the court. Although the final resolution of this complaint remains uncertain, based on information currently known to the Company's management, the Company does not expect this complaint will have a material adverse effect on its financial condition, results of operations or cash flows.

**Harbor Oil Inc. Site**

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS), which is expected to be finalized in the first half of 2011. The actual cleanup, if any, will not occur until the RI/FS is complete. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. The Company has accrued its share of the RI/FS ($0.5 million) for this matter.

**Spokane River Licensing**

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

As part of the Settlement Agreement with the Washington Department of Ecology (DOE), the Company participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, the DOE filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company's level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company has until May 27, 2012 to develop mitigation strategies to address the low levels of dissolved oxygen. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully identified or approved by the DOE. On July 16, 2010, the City of Post Falls and the Hayden Area Regional Sewer Board filed an appeal with the United States District Court for the District of Idaho with respect to the EPA's approval of the TMDL. The Company, the City of Coeur d'Alene, Kaiser Aluminum and the Spokane River Keeper subsequently moved to intervene in the appeal. The EPA, the City of Post Falls and the Hayden Area Regional Sewer Board are currently in settlement negotiations in an attempt to resolve the appeal.

The Company is implementing the environmental and operational conditions required in the license for the Spokane River Project. The estimated cost to implement the license conditions, which is the result of more than a dozen separate settlements, is $334 million over the 50-year license term. This will increase the Spokane River Project's cost of power by about 40 percent, while decreasing annual generation by approximately one-half of one percent. Costs to implement mitigation measures related to the TMDL are not included in these cost estimates. The IPUC and the WUTC approved the recovery of licensing costs through the general rate case settlements in 2009. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to implementing the license for the Spokane River Project.

**Cabinet Gorge Total Dissolved Gas Abatement Plan**

Dissolved atmospheric gas levels in the Clark Fork River exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. In 2002, the Company submitted a Gas Supersaturation Control Program (GSCP) to the Idaho Department of Environmental Quality (Idaho DEQ) and U.S. Fish and Wildlife Service (USFWS). This submission was part of the Clark Fork Settlement Agreement for licensing the use of Cabinet Gorge. The GSCP provided for the opening and modification of possibly two diversion tunnels around Cabinet Gorge to allow streamflow to be diverted when flows are in excess of powerhouse capacity. In 2007, engineering studies determined that the tunnels would not sufficiently reduce Total Dissolved Gas (TDG). In consultation with the Idaho DEQ and the USFWS, the Company developed an addendum to the GSCP. The GSCP addendum abandons the concept to reopen the two diversion tunnels and requires the Company to evaluate a variety of different options to abate TDG over the next several years. In March 2010, the FERC approved the GSCP addendum of preliminary design for alternative abatement measures. In May 2010, the Company initiated preliminary feasibility assessments for several alternative abatement measures, the results of which are anticipated in March 2011. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

**Fish Passage at Cabinet Gorge and Noxon Rapids**

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company is evaluating the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures. In the fall of 2009, the Company selected a contractor to design a permanent upstream passage facility at Cabinet Gorge. The Company anticipates that the design and cost estimates will be completed by the end of 2011.

In January 2010, the USFWS proposed to revise its 2005 designation of critical habitat for the bull trout. The proposed revisions include the lower Clark Fork River as critical habitat. In April 2010, the Company submitted comments recommending the lower Clark Fork River be excluded from critical habitat designation based in part on the extensive bull trout recovery efforts the Company is already undertaking. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

**Aluminum Recycling Site**

In October 2009, the Company (through its subsidiary Pentzer Venture Holdings II, Inc. (Pentzer)) received notice from the DOE proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act, under Washington state law.

Pentzer owns property that adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by DOE as "Aluminum Recycling — Trentwood." Operators of the UPR property maintained piles of aluminum "black dross," which can be designated as a state-only dangerous waste in Washington State. In the course of its business, the operators placed a portion of the aluminum dross pile on the property owned by Pentzer. Pentzer does not believe it is a contributor to any environmental contamination associated with the dross pile, and submitted a response to the DOE's proposed findings in November 2009. In December 2009, Pentzer received notice from the DOE that it had been designated as a potentially liable party for any hazardous substances located on this site. UPR completed a RI/FS Work Plan in June 2010. At that time, UPR requested a contribution from Pentzer towards the cost of performing the RI/FS and also an access agreement to investigate the material deposited on the Pentzer property. Pentzer concluded an access agreement with UPR in October 2010. UPR commenced the remedial investigation during the fourth quarter of 2010, which is expected to be completed in 2011. There is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred.

**Injury from Overhead Electric Line (Munderloh v. Avista)**

On March 4, 2010, the plaintiff and his wife filed a complaint against Avista Corp. in Spokane County Superior Court. Plaintiffs allege that while the plaintiff was employed by a third party as a laborer at their construction site, he came into contact with Avista Corp.'s electric line, was injured and suffered economic and non-economic damages. Plaintiffs further allege that Avista Corp. was at fault for failing to relocate the overhead electric line which it controlled and operated adjacent to the construction site. In addition to economic and non-economic damages, plaintiffs also seek damages for loss of consortium, attorney's fees and costs, prejudgment interest and punitive damages. Trial has been scheduled to begin in September 2011. The case is in the early stage of discovery and plaintiffs have not yet provided a statement specifying damages. Because the resolution of this claim remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect this complaint will have a material adverse effect on its financial condition, results of operations or cash flows.

**Natural Gas Line Safety Complaint**

In June 2010, the WUTC staff filed a complaint against the Company related to a natural gas explosion and fire that occurred in Odessa, Washington in December 2008 that injured two people. The WUTC staff alleges certain violations related to the installation of the low pressure natural gas distribution line, as well as the removal of the line following the explosion and fire. The WUTC staff made recommendations of fines that could exceed $1.1 million and that the Company implement certain measures to ensure compliance with WUTC laws and rules. In January 2011, the Company filed a settlement agreement with the WUTC that was approved by the WUTC in February 2011, and resolved all issues in this matter. As part of the settlement agreement, the Company accrued a fine of $0.2 million. In the fourth quarter of 2010, the Company reached separate legal settlement with the injured individuals in an amount that was not material to the Company's financial condition, results of operations or cash flows.

**Damages from Fire in Stevens County, Washington**

In August 2010, a fire in Stevens County, Washington occurred during a wind storm. The apparent cause of the fire may be a tree located outside of Avista Corp.'s right-of-way that came in contact with an electric line owned by Avista Corp. The fire area is a rural farm and timber landscape. The fire destroyed two residences and six outbuildings. The Company is not aware of any personal injuries resulting from the fire. Although no lawsuits have been filed, Avista Corp. has received several claims and it is possible that additional claims may be made and lawsuits may be filed against the Company. Because the resolution of this issue remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect this complaint will have a material adverse effect on its financial condition, results of operations or cash flows.

**Collective Bargaining Agreements**

The Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represents approximately 45 percent of all of Avista Utilities' employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expired on March 26, 2010. A new agreement was reached in October 2010 (expiring in March 2014). Two local agreements in Oregon, which cover approximately 50 employees, expired in April 2010. New agreements were reached in December 2010 (expiring in March 2014).

**Other Contingencies**

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material adverse impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

The Company routinely assesses, based on studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred. For matters that affect Avista Utilities' operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

The Company has potential liabilities under the Endangered Species Act for species of fish that have either already been added to the endangered species list, listed as "threatened" or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. The state of Montana is examining the status of all water right claims within state boundaries. Claims within the Clark Fork River basin could adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated an adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. In addition, the state of Washington has indicated its intent to initiate an adjudication for the Spokane River basin in the next several years. The Company is and will continue to be a participant in these adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time.

## NOTE 25. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2017. The largest of these contracts provides for increases due to changes in the cost of living index and further provides flexibility in the annual obligation from year-to-year subject to a three-year true-up cycle.

**Total payments under these contracts were as follows for the years ended December 31 (dollars in thousands):**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Information service contract payments | $ 13,426 | $ 15,529 | $ 15,446 |

The majority of the costs are included in other operating expenses in the Consolidated Statements of Income. Minimum contractual obligations under the Company's information services contracts are $12.8 million in 2011, $11.8 million in 2012, $9.3 million in 2013, $7.5 million in 2014 and $7.0 million in each of 2015, 2016 and 2017.

**Regulatory Assets and Liabilities**

**The following table presents the Company's regulatory assets and liabilities as of December 31, 2010 (dollars in thousands):**

| | Remaining Amortization Period | Receiving Regulatory Treatment: Earning A Return (1) | Receiving Regulatory Treatment: Not Earning A Return | Pending Regulatory Treatment (2) | Total 2010 | Total 2009 |
|---|---|---|---|---|---|---|
| **Regulatory assets:** | | | | | | |
| Investment in exchange power-net | 2019 | $ 21,233 | $ — | $ — | $ 21,233 | $ 23,683 |
| Regulatory assets for deferred income tax | (3) | — | 90,025 | — | 90,025 | 97,945 |
| Regulatory assets for pensions and other postretirement benefit plans | (4) | — | — | 178,985 | 178,985 | 141,085 |
| Current regulatory asset for utility derivatives | (5) | — | 48,891 | — | 48,891 | 8,332 |
| Power deferrals | (3) | 18,305 | — | — | 18,305 | 27,771 |
| Unamortized debt repurchase costs | (6) | 25,454 | — | — | 25,454 | 15,196 |
| Regulatory asset for settlement with Coeur d'Alene Tribe | 2059 | 54,056 | — | — | 54,056 | 55,134 |
| Demand side management programs | (3) | — | 4,251 | — | 4,251 | 11,894 |
| Montana lease payments | (3) | 6,134 | — | — | 6,134 | 7,171 |
| Lancaster Plant 2010 net costs | 2015 | 6,687 | — | — | 6,687 | — |
| Non-current regulatory asset for utility derivatives | (5) | — | 15,724 | — | 15,724 | — |
| Other regulatory assets | (3) | 5,662 | 4,542 | 6,044 | 16,248 | 20,430 |
| Total regulatory assets | | $ 137,531 | $ 163,433 | $ 185,029 | $ 485,993 | $ 408,641 |
| **Regulatory Liabilities:** | | | | | | |
| Residential exchange | | $ — | $ — | $ — | $ — | $ 2,900 |
| Oregon Senate Bill 408 | 2011-2012 | 2,545 | — | — | 2,545 | 1,790 |
| Natural gas deferrals | (3) | 22,074 | — | — | 22,074 | 39,952 |
| Regulatory liability for utility plant retirement costs | (7) | 223,131 | — | — | 223,131 | 217,176 |
| Non-current regulatory liability for utility derivatives | (5) | — | — | — | — | 42,611 |
| Income tax related liabilities | (3) | — | 28,353 | — | 28,353 | 13,045 |
| Regulatory liability for Spokane Energy | (8) | — | — | 17,076 | 17,076 | — |
| Other regulatory liabilities | (3) | 3,479 | 1,564 | — | 5,043 | 6,440 |
| Total regulatory liabilities | | $ 251,229 | $ 29,917 | $ 17,076 | $ 298,222 | $ 323,914 |

*(1) Earning a return includes either interest on the regulatory asset/liability, or a return on the investment as a component of rate base or the weighted cost of capital.*

*(2) Pending regulatory treatment includes regulatory assets and liabilities that have prior regulatory precedent.*

*(3) Remaining amortization period varies depending on timing of underlying transactions.*

*(4) As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency.*

*(5) The WUTC and the IPUC issued accounting orders authorizing Avista Utilities to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Utilities 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.*

*(6) For the Company's Washington jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are recovered through retail rates as a component of interest expense.*

*(7) This amount is dependent upon the cost of removal of underlying utility plant assets and the life of utility plant.*

*(8) Consists of a regulatory liability recorded for the cumulative retained earnings of Spokane Energy that the Company will flow through regulatory accounting mechanisms in future periods.*

### Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Consolidated Balance Sheets for future review and recovery through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

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

In Washington, the Energy Recovery Mechanism (ERM) allows Avista Utilities to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual net power supply costs and the amount included in base retail rates for Washington customers. In the 2010 Washington general rate case settlement, the parties agreed that there would be no deferrals under the ERM for 2010. Deferrals under the ERM will resume in 2011. The Company 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.

The initial amount of power supply costs in excess or below the level in retail rates, which the Company either incurs the cost of, or receives the benefit from, is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. The Company will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. The Company shares annual power supply cost variances between $4.0 million and $10.0 million with its 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, 90 percent of the cost variance is deferred for future surcharge or rebate. The Company absorbs or receives the benefit in power supply costs of the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates.

**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% |

Avista Utilities has a Power Costs Adjustment (PCA) mechanism in Idaho that allows it to modify electric rates on October 1 of each year with Idaho Public Utilities Commission (IPUC) approval. Under the PCA mechanism, Avista Utilities defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. In June 2007, the IPUC approved continuation of the PCA mechanism with an annual rate adjustment provision. These annual October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period.

**The following table shows activity in deferred power costs for Washington and Idaho during 2008, 2009 and 2010 (dollars in thousands):**

| | Washington | Idaho | Total |
|---|---|---|---|
| Deferred power costs as of January 1, 2008 | $ 58,524 | $ 21,163 | $ 79,687 |
| Activity from January 1 — December 31, 2008: | | | |
| Power costs deferred | 7,049 | 10,029 | 17,078 |
| Interest and other net additions | 2,231 | 1,153 | 3,384 |
| Recovery of deferred power costs through retail rates | (30,852) | (11,690) | (42,542) |
| Deferred power costs as of December 31, 2008 | 36,952 | 20,655 | 57,607 |
| Activity from January 1 — December 31, 2009: | | | |
| Power costs deferred | — | 17,985 | 17,985 |
| Interest and other net additions | 879 | 388 | 1,267 |
| Recovery of deferred power costs through retail rates | (31,567) | (17,521) | (49,088) |
| Deferred power costs as of December 31, 2009 | 6,264 | 21,507 | 27,771 |
| Activity from January 1 — December 31, 2010: | | | |
| Power costs deferred | — | 9,768 | 9,768 |
| Interest and other net additions | 538 | 26 | 564 |
| Recovery of deferred power costs through retail rates | (6,802) | (12,996) | (19,798) |
| Deferred power costs as of December 31, 2010 | $ — | $ 18,305 | $ 18,305 |

## Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Utilities files a purchased gas cost adjustment (PGA) in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. These annual PGA filings in Washington and Idaho provide for the deferral, and recovery or refund, of 100 percent of the difference between actual and estimated commodity and pipeline transportation costs, subject to applicable regulatory review.

The annual PGA filing in Oregon provides for deferral, and recovery or refund, of 100 percent of the difference between actual and estimated pipeline transportation costs and commodity costs that are fixed through hedge transactions. Commodity costs that are not hedged for Oregon customers are subject to a sharing mechanism whereby Avista Utilities defers, and recovers or refunds, 90 percent of the difference between these actual and estimated costs. Total net deferred natural gas costs to be refunded to customers were a liability of $22.1 million as of December 31, 2010 and $40.0 million as of December 31, 2009.

## General Rate Cases

**The following is a summary of the Company's authorized rates of return in each jurisdiction:**

| Jurisdiction and service | Implementation Date | Authorized Overall Rate of Return | Authorized Return on Equity | Authorized Equity Level |
|---|---|---|---|---|
| Washington electric and natural gas | December 2010 | 7.91% | 10.2% | 46.5% |
| Idaho electric and natural gas | October 2010 | (1) | (1) | (1) |
| Oregon natural gas | November 2009 | 8.19% | 10.1% | 50.0% |

*(1) The rate adjustment implemented on October 1, 2010 resulting from the Idaho electric and natural gas general rate case settlement did not have a specific authorized rate of return, return on equity or equity level. The prior rate case settlement implemented in August 2009 had an authorized rate of return of 8.55 percent, a return on equity of 10.5 percent and authorized equity level of 50.0 percent.*

### Washington General Rate Cases

In September 2008, Avista Corp. entered into a settlement stipulation in its general rate case that was filed with the WUTC in March 2008. This settlement stipulation was approved by the WUTC in December 2008. The new electric and natural gas rates became effective on January 1, 2009. As agreed to in the settlement, base electric rates for the Company's Washington customers increased by an average of 9.1 percent, which was designed to increase annual revenues by $32.5 million. Base natural gas rates for the Company's Washington customers increased by an average of 2.4 percent, which was designed to increase annual revenues by $4.8 million.

In December 2009, the WUTC issued an order on Avista Corp.'s electric and natural gas rate general rate cases that were filed with the WUTC in January 2009. The WUTC approved a base electric rate increase for the Company's Washington customers of 2.8 percent, which was designed to increase annual revenues by $12.1 million. Base natural gas rates for the Company's 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 this general rate case order, the WUTC did not allow the Company to include the costs associated with the power purchase agreement for the Lancaster Plant in rates. The Company subsequently filed for and received approval for deferred accounting treatment for these net costs.

In August 2010, the Company entered into an all-party settlement agreement that resolved all issues with respect to its general rate case filed with the WUTC in March 2010. This settlement agreement was approved by the WUTC in November 2010. As agreed to in the settlement stipulation, electric rates for the Company's 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 the Company's 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. As part of the settlement, the parties agreed that the Company would not file a general rate case in the Washington jurisdiction before April 1, 2011.

The parties agreed that recovery of the deferred net costs associated with the power purchase agreement for the Lancaster Plant were limited to $6.8 million for 2010. These net deferred costs will be recovered over a five-year amortization period with a rate of return on the unamortized balance. The parties agreed that the costs for the Lancaster Plant for 2011 and going forward are reasonable and should be recovered in rates.

As part of the settlement related to the 2010 Lancaster Plant deferred net costs, the parties agreed that there would be no deferrals under the ERM for 2010 in either the surcharge or rebate direction. For 2010, the Company received all of the benefit from the amount of power supply costs below the level in retail rates in Washington. Deferrals under the ERM will resume in 2011.

### Idaho General Rate Cases

In August 2008, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the IPUC in April 2008. This settlement stipulation was approved by the IPUC in September 2008. The new electric and natural gas rates became effective on October 1, 2008. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 12.0 percent, which was designed to increase annual revenues by $23.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 4.7 percent, which was designed to increase annual revenues by $3.9 million.

In June 2009, the Company entered into an all-party settlement stipulation in its electric and natural gas general rate cases that were filed with the IPUC in January 2009. This settlement stipulation was approved by the IPUC in July 2009.

The new electric and natural gas rates became effective on August 1, 2009. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 5.7 percent, which was designed to increase annual revenues by $12.5 million. Offsetting the base electric rate increase was an overall 4.2 percent decrease in the PCA surcharge, which was designed to decrease annual PCA revenues by $9.3 million, resulting in a net increase in annual revenues of $3.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 2.1 percent, which was designed to increase annual revenues by $1.9 million. Offsetting the natural gas rate increase for residential customers was an equivalent PGA decrease of 2.1 percent. Large general services customers received a PGA decrease of 2.4 percent and interruptible services customers received a PGA decrease of 2.8 percent. The overall PGA decrease resulted in a $2.0 million decrease in annual PGA revenues, resulting in a net decrease in annual revenues of $0.1 million. The PGAs are designed to pass through changes in natural gas costs to customers with no change in gross margin or net income.

In September 2010, the IPUC approved a settlement agreement with respect to the Company's 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 the Company's 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 the Company's Idaho customers increased by an average of 2.6 percent, which was designed to increase annual revenues by $1.8 million.

The settlement agreement includes a rate mitigation plan under which the impact on customers of the new rates will be 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 the Company's cash collections from customers will be reduced by this amortization during the two-year period, the mitigation plan will have no impact on the Company's net income. Retail rates will increase on October 1, 2011 and October 1, 2012 as the deferred state income tax balance is amortized to zero.

**Oregon General Rate Cases**

As approved by the OPUC in March 2008, natural gas rates for the Company's Oregon customers increased 0.4 percent effective April 1, 2008 (designed to increase annual revenues by $0.5 million) and increased an additional 1.1 percent effective November 1, 2008 (designed to increase annual revenues by an additional $1.4 million).

In September 2009, the Company entered into an all-party settlement stipulation in its 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 Oregon customers increased by an average of 7.1 percent, which was designed to increase annual revenues by $8.8 million.

In February 2011, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the OPUC in September 2010. The settlement, which is subject to approval by the OPUC, provides for an overall rate increase of 3.1 percent for the Company's Oregon customers, designed to increase annual revenues by $3.0 million. Part of the rate increase would become effective March 15, 2011, with the remaining increase effective June 1, 2011. The settlement is based on an overall rate of return of 8.0 percent, with a common equity ratio of 50.0 percent and a 10.1 percent return on equity. The Company's original request was for an overall rate increase of 5.6 percent, designed to increase annual revenues by $5.4 million. The Company's original request was based on an overall rate of return of 8.61 percent, with a common equity ratio of 50.8 percent and a 10.9 percent return on equity.

## NOTE 27. INFORMATION BY BUSINESS SEGMENTS

The business segment presentation reflects the basis used by the Company's management to analyze performance and determine the allocation of resources. Avista Utilities' business is managed based on the total regulated utility operation. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. The Other category, which is not a reportable segment, includes the remaining activities of Avista Energy, other investments and operations of various subsidiaries, as well as certain other operations of Avista Capital.

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

| | Avista Utilities | Advantage IQ | Other | Total Non-Utility | Intersegment Eliminations [1] | Total |
|---|---|---|---|---|---|---|
| **For the year ended December 31, 2010:** | | | | | | |
| Operating revenues | $ 1,419,646 | $ 102,035 | $ 61,067 | $ 163,102 | $ (24,008) | $ 1,558,740 |
| Resource costs | 795,075 | — | 35,397 | 35,397 | (24,008) | 806,464 |
| Other operating expenses | 242,521 | 80,100 | 18,449 | 98,549 | — | 341,070 |
| Depreciation and amortization | 100,554 | 6,070 | 1,002 | 7,072 | — | 107,626 |
| Income from operations | 208,104 | 15,865 | 6,219 | 22,084 | — | 230,188 |
| Interest expense [2] | 70,867 | 276 | 5,530 | 5,806 | (249) | 76,424 |
| Income taxes | 46,428 | 5,679 | (950) | 4,729 | — | 51,157 |
| Net income (loss) attributable to Avista Corporation | 86,681 | 7,433 | (1,689) | 5,744 | — | 92,425 |
| Capital expenditures | 202,227 | 1,932 | 497 | 2,429 | — | 204,656 |
| **For the year ended December 31, 2009:** | | | | | | |
| Operating revenues | $ 1,395,201 | $ 77,275 | $ 40,089 | $ 117,364 | $ — | $ 1,512,565 |
| Resource costs | 799,539 | — | 23,408 | 23,408 | — | 822,947 |
| Other operating expenses | 229,907 | 60,985 | 21,710 | 82,695 | — | 312,602 |
| Depreciation and amortization | 93,783 | 4,687 | 1,305 | 5,992 | — | 99,775 |
| Income (loss) from operations | 195,389 | 11,603 | (6,334) | 5,269 | — | 200,658 |
| Interest expense [2] | 66,688 | 302 | 231 | 533 | (187) | 67,034 |
| Income taxes | 44,480 | 3,969 | (2,126) | 1,843 | — | 46,323 |
| Net income (loss) attributable to Avista Corporation | 86,744 | 5,329 | (5,002) | 327 | — | 87,071 |
| Capital expenditures | 205,384 | 3,031 | 89 | 3,120 | — | 208,504 |
| **For the year ended December 31, 2008:** | | | | | | |
| Operating revenues | $ 1,572,664 | $ 59,085 | $ 45,014 | $ 104,099 | $ — | $ 1,676,763 |
| Resource costs | 1,031,989 | — | 23,553 | 23,553 | — | 1,055,542 |
| Other operating expenses | 206,528 | 44,349 | 20,744 | 65,093 | — | 271,621 |
| Depreciation and amortization | 87,845 | 3,439 | 1,348 | 4,787 | — | 92,632 |
| Income (loss) from operations | 174,245 | 11,297 | (631) | 10,666 | — | 184,911 |
| Interest expense [2] | 79,401 | 110 | 157 | 267 | (81) | 79,587 |
| Income taxes | 41,527 | 4,067 | 31 | 4,098 | — | 45,625 |
| Net income (loss) attributable to Avista Corporation | 70,032 | 6,090 | (2,502) | 3,588 | — | 73,620 |
| Capital expenditures | 219,239 | 3,485 | 175 | 3,660 | — | 222,899 |
| **Total Assets:** | | | | | | |
| As of December 31, 2010 | $ 3,589,235 | $ 221,086 | $ 129,774 | $ 350,860 | $ — | $ 3,940,095 |
| As of December 31, 2009 | $ 3,400,384 | $ 143,060 | $ 63,515 | $ 206,575 | $ — | $ 3,606,959 |

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

*(2) Including interest expense to affiliated trusts.*

## NOTE 28. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The Company's energy operations are significantly affected by weather conditions. Consequently, there can be large variances in revenues, expenses and net income between quarters based on seasonal factors such as, but not limited to, temperatures and streamflow conditions.

**A summary of quarterly operations (in thousands, except per share amounts) for 2010 and 2009 follows:**

| | Three Months Ended | | | |
|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 |
| **2010** | | | | |
| Operating revenues | $ 456,415 | $ 360,733 | $ 367,172 | $ 374,420 |
| Operating expenses | 388,591 | 298,984 | 329,428 | 311,549 |
| Income from operations | $ 67,824 | $ 61,749 | $ 37,744 | $ 62,871 |
| Net income | $ 29,317 | $ 26,047 | $ 13,334 | $ 26,250 |
| Less: Net income attributable to noncontrolling interests | (507) | (507) | (988) | (521) |
| Net income attributable to Avista Corporation | $ 28,810 | $ 25,540 | $ 12,346 | $ 25,729 |
| Outstanding common stock: | | | | |
| Weighted average, basic | 54,869 | 55,031 | 55,616 | 56,835 |
| Weighted average, diluted | 55,115 | 55,231 | 55,801 | 57,126 |
| Earnings per common share attributable to Avista Corporation, diluted | $ 0.52 | $ 0.46 | $ 0.22 | $ 0.45 |
| **2009** | | | | |
| Operating revenues | $ 487,470 | $ 307,111 | $ 314,692 | $ 403,292 |
| Operating expenses | 421,625 | 249,029 | 290,938 | 350,315 |
| Income from operations | $ 65,845 | $ 58,082 | $ 23,754 | $ 52,977 |
| Net income | $ 31,419 | $ 26,289 | $ 8,634 | $ 22,305 |
| Less: Net income attributable to noncontrolling interests | (393) | (437) | (495) | (252) |
| Net income attributable to Avista Corporation | $ 31,026 | $ 25,852 | $ 8,139 | $ 22,053 |
| Outstanding common stock: | | | | |
| Weighted average, basic | 54,616 | 54,654 | 54,706 | 54,796 |
| Weighted averaged, diluted | 54,722 | 54,827 | 55,094 | 55,122 |
| Earnings per common share attributable to Avista Corporation, diluted | $ 0.57 | $ 0.47 | $ 0.15 | $ 0.40 |

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

## ITEM 9A. CONTROLS AND PROCEDURES

### Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company has disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) to ensure that information required to be disclosed in the reports it files or submits under the Act is recorded, processed, summarized and reported on a timely basis. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Act is accumulated and communicated to the Company's management, including its principal executive and principal financial officers as appropriate to allow timely decisions regarding required disclosure. Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company evaluated its disclosure controls and procedures as of the end of the period covered by this report. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. Based upon the Company's evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures are effective at a reasonable assurance level as of December 31, 2010.

### Management's Report on Internal Control Over Financial Reporting

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). The Company's internal control over financial reporting is a process designed under the supervision of the Company's principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

Under the supervision and with the participation of the Company's management, including the Company's principal executive officer and principal financial officer, the Company conducted an assessment of the effectiveness of the Company's internal control over financial reporting based on the framework established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company's internal control over financial reporting as of December 31, 2010 is effective at a reasonable assurance level.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, has issued an attest report on the Company's internal control over financial reporting as of December 31, 2010.

### Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting that occurred during the Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Avista Corporation and subsidiaries (the "Company") as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010 of the Company and our report dated February 25, 2011 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's adoption of Accounting Standards Update No. 2009-17, *Consolidations — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities.*

/s/ Deloitte & Touche LLP

Seattle, Washington
February 25, 2011

## ITEM 9B. OTHER INFORMATION

None.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding the directors of the Registrant and compliance with Section 16(a) of the Exchange Act has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 12, 2011.

**Executive Officers of the Registrant**

| Name | Age | Business Experience |
|---|---|---|
| **Scott L. Morris** | 53 | Chairman, President and Chief Executive Officer effective January 1, 2008. Director since February 9, 2007; President and Chief Operating Officer May 2006 — December 2007; Senior Vice President February 2002 — May 2006; Vice President November 2000 — February 2002; President — Avista Utilities August 2000 — December 2008; General Manager — Avista Utilities for the Oregon and California operations October 1991 — August 2000; various other management and staff positions with the Company since 1981. |
| **Mark T. Thies** | 47 | Senior Vice President and Chief Financial Officer (Principal Financial Officer) since September 2008; prior to employment with the Company held the following positions with Black Hills Corporation: Executive Vice President and Chief Financial Officer March 2003 to January 2008; Senior Vice President and Chief Financial Officer March 2000 to March 2003; Controller May 1997 to March 2000. |
| **Marian M. Durkin** | 57 | Senior Vice President, General Counsel and Chief Compliance Officer since November 2005; Senior Vice President and General Counsel August 2005 — November 2005; prior to employment with the Company: held several legal positions with United Air Lines, Inc. from 1995 to August 2005, most recently served as Vice President Deputy General Counsel and Assistant Secretary. |
| **Karen S. Feltes** | 55 | Senior Vice President of Human Resources and Corporate Secretary since November 2005; Vice President of Human Resources and Corporate Secretary March 2003 — November 2005; Vice President of Human Resources and Corporate Services February 2002 — March 2003; various human resources positions with the Company April 1998 — February 2002. |
| **Dennis P. Vermillion** | 49 | Senior Vice President since January 2010; Vice President July 2007- December 2009; President — Avista Utilities since January 2009; Vice President of Energy Resources and Optimization — Avista Utilities July 2007 — December 2008; President and Chief Operating Officer of Avista Energy February 2001 — July 2007; various other management and staff positions with the Company since 1985. |
| **Christy M. Burmeister-Smith** | 54 | Vice President, Controller and Principal Accounting Officer since May 2007. Vice President and Treasurer January 2006 — May 2007; Vice President and Controller June 1999 — January 2006; various other management and staff positions with the Company since 1980. |
| **James M. Kensok** | 52 | Vice President and Chief Information Officer since January 2007; Chief Information Officer February 2001 — December 2006; various other management and staff positions with the Company since 1996. |
| **Don F. Kopczynski** | 55 | Vice President since May 2004; Vice President of Transmission and Distribution Operations — Avista Utilities since May 2004; various other management and staff positions with the Company and its subsidiaries since 1979. |

**Executive Officers of the Registrant**

| Name | Age | Business Experience |
|---|---|---|
| **David J. Meyer** | 57 | Vice President and Chief Counsel for Regulatory and Governmental Affairs since February 2004; Senior Vice President and General Counsel September 1998 — February 2004. |
| **Kelly O. Norwood** | 52 | Vice President since November 2000; Vice President of State and Federal Regulation — Avista Utilities since March 2002; Vice President and General Manager of Energy Resources — Avista Utilities August 2000 — March 2002; various other management and staff positions with the Company since 1981. |
| **Richard L. Storro** | 60 | Vice President since January 2009; Vice President Energy Resources — Avista Utilities since January 2009. Various other management and staff positions with the Company since 1973. |
| **Jason R. Thackston** | 40 | Vice President of Finance since June 2009; various other management and staff positions with the Company since 1996. |
| **Roger D. Woodworth** | 54 | Vice President since November 1998; Vice President, Sustainable Energy Solutions Avista Utilities since February 2007; Vice President, Customer Solutions for Avista Utilities March 2003 — February 2007; Vice President of Utility Operations of Avista Utilities September 2001 — March 2003; Vice President — Corporate Development November 1998 — September 2001; various other management and staff positions with the Company since 1979. |

All of the Company's executive officers, with the exception of James M. Kensok, Don F. Kopczynski, David J. Meyer, Kelly O. Norwood and Richard L. Storro, were officers or directors of one or more of the Company's subsidiaries in 2010. The Company's executive officers are elected annually by the Board of Directors.

The Company has adopted a Code of Business Conduct and Ethics (Code of Conduct) for directors, officers (including the principal executive officer, principal financial officer and principal accounting officer), and employees. The Code of Conduct is available on the Company's Web site at www.avistacorp.com and will also be provided to any shareholder without charge upon written request to:

Avista Corp.
General Counsel
P.O. Box 3727 MSC-12
Spokane, Washington 99220-3727

Any changes to or waivers for executive officers and directors of the Company's Code of Conduct will be posted on the Company's Web site.

## ITEM 11. EXECUTIVE COMPENSATION

Information regarding executive compensation has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 12, 2011.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

(a) Security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities):

Information regarding security ownership of certain beneficial owners (owning 5 percent or more of Registrant's voting securities) has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 12, 2011.

(b) Security ownership of management:

Information regarding security ownership of management has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 12, 2011.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2010:

| Plan category | (a) Number of securities to be issued upon exercise of outstanding options, warrants and rights [1] | (b) Weighted average exercise price of outstanding options, warrants and rights | (c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) |
|---|---|---|---|
| Equity compensation plans approved by security holders [2] | 130,500 | $ 11.82 | 541,946 |
| Equity compensation plans not approved by security holders [3] | 71,174 | $ 10.99 | 1,862,874 |
| Total | 201,674 | $ 11.53 | 2,404,820 |

*(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long Term Incentive Plan. At December 31, 2010, 84,134 Restricted Share awards were outstanding. Performance share awards may be paid out at zero shares at a minimum achievement level; 325,700 shares at target level; or 488,550 shares at a maximum level. Because there is no exercise price associated with restricted shares or performance share awards, such shares are not included in the weighted-average price calculation.*

*(2) Includes the Long-Term Incentive Plan approved by shareholders in 1998 and the Non-Employee Director Stock Plan approved by shareholders in 1996. In February 2005, the Board of Directors elected to terminate the Non-Employee Director Stock Plan.*

*(3) Represents stock options outstanding and stock available for future issuance under the Non-Officer Employee Long-Term Incentive Plan, which was adopted by the Company in 2000. The Company currently does not plan to issue any further options or securities under this plan. Under this plan, employees (excluding directors and executive officers) of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards, performance awards, other stock-based awards and dividend equivalent rights. Stock options granted under this plan are equal to the market price of the Company's common stock on the date of grant. Stock options granted under this plan have terms of up to 10 years and generally vest at a rate of 25 percent per year over a four-year period.*

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 12, 2011.

## ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services has been omitted pursuant to General Instruction G to Form 10-K. Reference is made to the Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Registrant's annual meeting of shareholders to be held on May 12, 2011.

# PART IV

## ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements (Included in Part II of this report):

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income for the Years Ended December 31, 2010, 2009 and 2008

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2010, 2009 and 2008

Consolidated Balance Sheets as of December 31, 2010 and 2009

Consolidated Statements of Cash Flows for the Years Ended December 31, 2010, 2009 and 2008

Consolidated Statements of Equity and Redeemable Noncontrolling Interests for the Years Ended December 31, 2010, 2009 and 2008

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 105. The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K pursuant to Item 15(b).

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**AVISTA CORPORATION**

| | |
|---|---|
| February 25, 2011 | By /s/ Scott L. Morris |
| Date | Scott L. Morris<br>Chairman of the Board, President and Chief Executive Officer |

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ Scott L. Morris<br>Scott L. Morris<br>Chairman of the Board,<br>President and Chief Executive Officer | Principal Executive Officer | February 25, 2011 |
| /s/ Mark T. Thies<br>Mark T. Thies (Senior Vice President<br>and Chief Financial Officer) | Principal Financial Officer | February 25, 2011 |
| /s/ Christy M. Burmeister-Smith<br>Christy M. Burmeister-Smith (Vice President,<br>Controller and Principal Accounting Officer) | Principal Accounting Officer | February 25, 2011 |
| /s/ Erik J. Anderson<br>Erik J. Anderson | Director | February 25, 2011 |
| /s/ Kristianne Blake<br>Kristianne Blake | Director | February 25, 2011 |
| /s/ John F. Kelly<br>John F. Kelly | Director | February 25, 2011 |
| /s/ Rebecca A. Klein<br>Rebecca A. Klein | Director | February 25, 2011 |
| /s/ Michael L. Noël<br>Michael L. Noël | Director | February 25, 2011 |
| /s/ Marc Racicot<br>Marc Racicot | Director | February 25, 2011 |
| /s/ Heidi B. Stanley<br>Heidi B. Stanley | Director | February 25, 2011 |
| /s/ R. John Taylor<br>R. John Taylor | Director | February 25, 2011 |

| | Previously Filed [1] | | |
|---|---|---|---|
| Exhibit | With Registration Number | As Exhibit | |
| 3(i) | 1-3701 (with June 30, 2008 Form 10-Q) | 3(i) | Restated Articles of Incorporation of Avista Corporation as amended and restated June 6, 2008. |
| 3(ii) | 1-3701 (with Form 8-K dated as of May 9, 2008) | 3(ii) | Bylaws of Avista Corporation, as amended May 9, 2008. |
| 4.1 | 2-4077 | B-3 | Mortgage and Deed of Trust, dated as of June 1, 1939. |
| 4.2 | 2-9812 | 4(c) | First Supplemental Indenture, dated as of October 1, 1952. |
| 4.3 | 2-60728 | 2(b)-2 | Second Supplemental Indenture, dated as of May 1, 1953. |
| 4.4 | 2-13421 | 4(b)-3 | Third Supplemental Indenture, dated as of December 1, 1955. |
| 4.5 | 2-13421 | 4(b)-4 | Fourth Supplemental Indenture, dated as of March 15, 1967. |
| 4.6 | 2-60728 | 2(b)-5 | Fifth Supplemental Indenture, dated as of July 1, 1957. |
| 4.7 | 2-60728 | 2(b)-6 | Sixth Supplemental Indenture, dated as of January 1, 1958. |
| 4.8 | 2-60728 | 2(b)-7 | Seventh Supplemental Indenture, dated as of August 1, 1958. |
| 4.9 | 2-60728 | 2(b)-8 | Eighth Supplemental Indenture, dated as of January 1, 1959. |
| 4.10 | 2-60728 | 2(b)-9 | Ninth Supplemental Indenture, dated as of January 1, 1960. |
| 4.11 | 2-60728 | 2(b)-10 | Tenth Supplemental Indenture, dated as of April 1, 1964. |
| 4.12 | 2-60728 | 2(b)-11 | Eleventh Supplemental Indenture, dated as of March 1, 1965. |
| 4.13 | 2-60728 | 2(b)-12 | Twelfth Supplemental Indenture, dated as of May 1, 1966. |
| 4.14 | 2-60728 | 2(b)-13 | Thirteenth Supplemental Indenture, dated as of August 1, 1966. |
| 4.15 | 2-60728 | 2(b)-14 | Fourteenth Supplemental Indenture, dated as of April 1, 1970. |
| 4.16 | 2-60728 | 2(b)-15 | Fifteenth Supplemental Indenture, dated as of May 1, 1973. |
| 4.17 | 2-60728 | 2(b)-16 | Sixteenth Supplemental Indenture, dated as of February 1, 1975. |
| 4.18 | 2-60728 | 2(b)-17 | Seventeenth Supplemental Indenture, dated as of November 1, 1976. |
| 4.19 | 2-69080 | 2(b)-18 | Eighteenth Supplemental Indenture, dated as of June 1, 1980. |
| 4.20 | 1-3701 (with 1980 Form 10-K) | 4(a)-20 | Nineteenth Supplemental Indenture, dated as of January 1, 1981. |
| 4.21 | 2-79571 | 4(a)-21 | Twentieth Supplemental Indenture, dated as of August 1, 1982. |
| 4.22 | 1-3701 (with Form 8-K dated September 20, 1983) | 4(a)-22 | Twenty-First Supplemental Indenture, dated as of September 1, 1983. |

| | Previously Filed[1] | | |
|---|---|---|---|
| Exhibit | With Registration Number | As Exhibit | |
| 4.23 | 2-94816 | 4(a)-23 | Twenty-Second Supplemental Indenture, dated as of March 1, 1984. |
| 4.24 | 1-3701 (with 1986 Form 10-K) | 4(a)-24 | Twenty-Third Supplemental Indenture, dated as of December 1, 1986. |
| 4.25 | 1-3701 (with 1987 Form 10-K) | 4(a)-25 | Twenty-Fourth Supplemental Indenture, dated as of January 1, 1988. |
| 4.26 | 1-3701 (with 1989 Form 10-K) | 4(a)-26 | Twenty-Fifth Supplemental Indenture, dated as of October 1, 1989. |
| 4.27 | 33-51669 | 4(a)-27 | Twenty-Sixth Supplemental Indenture, dated as of April 1, 1993. |
| 4.28 | 1-3701 (with 1993 Form 10-K) | 4(a)-28 | Twenty-Seventh Supplemental Indenture, dated as of January 1, 1994. |
| 4.29 | 1-3701 (with 2001 Form 10-K) | 4(a)-29 | Twenty-Eighth Supplemental Indenture, dated as of September 1, 2001. |
| 4.30 | 333-82502 | 4(b) | Twenty-Ninth Supplemental Indenture, dated as of December 1, 2001. |
| 4.31 | 1-3701 (with June 30, 2002 10-Q) | 4(f) | Thirtieth Supplemental Indenture, dated as of May 1, 2002. |
| 4.32 | 333-39551 | 4(b) | Thirty-First Supplemental Indenture, dated as of May 1, 2003. |
| 4.33 | 1-3701 (with September 30, 2003 10-Q) | 4(f) | Thirty-Second Supplemental Indenture, dated as of September 1, 2003. |
| 4.34 | 333-64652 | 4(a)33 | Thirty-Third Supplemental Indenture, dated as of May 1, 2004. |
| 4.35 | 1-3701 (with Form 8-K dated as of December 15, 2004) | 4.1 | Thirty-Fourth Supplemental Indenture, dated as of November 1, 2004. |
| 4.36 | 1-3701 (with Form 8-K dated as of December 15, 2004) | 4.2 | Thirty-Fifth Supplemental Indenture, dated as of December 1, 2004. |
| 4.37 | 1-3701 (with Form 8-K dated as of December 15, 2004) | 4.3 | Thirty-Sixth Supplemental Indenture, dated as of December 1, 2004. |
| 4.38 | 1-3701 (with Form 8-K dated as of December 15, 2004) | 4.4 | Thirty-Seventh Supplemental Indenture, dated as of December 1, 2004. |
| 4.39 | 1-3701 (with Form 8-K dated as of May 12, 2005) | 4.1 | Thirty-Eighth Supplemental Indenture, dated as of May 1, 2005. |

| | Previously Filed[1] | | |
|---|---|---|---|
| Exhibit | With Registration Number | As Exhibit | |
| 4.40 | 1-3701 (with Form 8-K dated as of November 17, 2005) | 4.1 | Thirty-Ninth Supplemental Indenture, dated as of November 1, 2005. |
| 4.41 | 1-3701 (with Form 8-K dated as of April 6, 2006) | 4.1 | Fortieth Supplemental Indenture, dated as of April 1, 2006. |
| 4.42 | 1-3701 (with Form 8-K dated as of December 15, 2006) | 4.1 | Forty-First Supplemental Indenture, dated as of December 1, 2006. |
| 4.43 | 1-3701 (with Form 8-K dated as of April 3, 2008) | 4.1 | Forty-Second Supplemental Indenture, dated as of April 1, 2008. |
| 4.44 | 1-3701 (with Form 8-K dated as of November 26, 2008) | 4.1 | Forty-Third Supplemental Indenture, dated as of November 1, 2008. |
| 4.45 | 1-3701 (with Form 8-K dated as of December 16, 2008) | 4.1 | Forty-Fourth Supplemental Indenture, dated as of December 1, 2008. |
| 4.46 | 1-3701 (with Form 8-K dated as of December 30, 2008) | 4.3 | Forty-Fifth Supplemental Indenture, dated as of December 1, 2008. |
| 4.47 | 1-3701 (with Form 8-K dated as of September 15, 2009) | 4.1 | Forty-Sixth Supplemental Indenture, dated as of September 1, 2009. |
| 4.48 | 1-3701 (with Form 8-K dated as of November 25, 2009) | 4.1 | Forty-Seventh Supplemental Indenture, dated as of November 1, 2009. |
| 4.49 | 1-3701 (with Form 8-K dated as of December 15, 2010) | 4.5 | Forty-Eighth Supplemental Indenture, dated as of December 1, 2010. |
| 4.50 | 1-3701 (with Form 8-K dated as of December 20, 2010) | 4.1 | Forty-Ninth Supplemental Indenture, dated as of December 1, 2010. |
| 4.51 | 1-3701 (with Form 8-K dated as of December 30, 2010) | 4.1 | Fiftieth Supplemental Indenture, dated as of December 1, 2010. |
| 4.52 | 1-3701 (with Form 8-K dated as of February 11, 2011) | 4.1 | Fifty-First Supplemental Indenture, dated as of February 1, 2011. |

| | Previously Filed [1] | | |
|---|---|---|---|
| Exhibit | With Registration Number | As Exhibit | |
| 4.53 | 1-3701 (with Form 8-K dated as of December 15, 2004) | 4.5 | Supplemental Indenture No. 1, dated as of December 1, 2004 to the Indenture dated as of April 1, 1998 between Avista Corporation and JPMorgan Chase Bank, N.A. |
| 4.54 | 333-82165 | 4(a) | Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee. |
| 4.55 | 1-3701 (with Form 8-K dated as of December 15, 2010) | 4.1 | Loan Agreement between City of Forsyth, Montana and Avista Corporation $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A dated as of December 1, 2010. |
| 4.56 | 1-3701 (with Form 8-K dated as of December 15, 2010) | 4.3 | Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010A, dated as of December 1, 2010. |
| 4.57 | 1-3701 (with Form 8-K dated as of December 15, 2010) | 4.2 | Loan Agreement between City of Forsyth, Montana and Avista Corporation $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B dated as of December 1, 2010. |
| 4.58 | 1-3701 (with Form 8-K dated as of December 15, 2010) | 4.4 | Trust Indenture between City of Forsyth, and the Bank of New York Mellon Trust Company, N.A., as Trustee, $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2010B, dated as of December 1, 2010. |
| 10.1 | 1-3701 (with Form 8-K dated as of February 11, 2011) | 10.1 | Credit Agreement, dated as of February 11, 2011, among Avista Corporation, the Banks Party hereto, The Bank of New York Mellon, Keybank National Association, and U.S. Bank National Association, as Co-Documentation Agents, Wells Fargo Bank National Association as Syndication Agent and an Issuing Bank, and Union Bank N.A. as Administrative Agent and an Issuing Bank. |
| 10.2 | 1-3701 (with Form 8-K dated as of February 11, 2011) | 10.2 | Bond Delivery Agreement, dated as of February 11, 2011, between Avista Corporation and Union Bank, N.A. |
| 10.3 | 2-13788 | 13(e) | Power Sales Contract (Rocky Reach Project) with Public Utility District No. 1 of Chelan County, Washington, dated as of November 14, 1957. |
| 10.4 | 2-60728 | 10(b)-1 | Amendment to Power Sales Contract (Rocky Reach Project) with Public Utility District No. 1 of Chelan County, Washington, dated as of June 1, 1968. |
| 10.5 | 1-3701 (with 2002 Form 10-K) | 10(b)-3 | Priest Rapids Project Product Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development). |

| | Previously Filed[1] | | |
|---|---|---|---|
| Exhibit | With Registration Number | As Exhibit | |
| 10.6 | 1-3701 (with 2002 Form 10-K) | 10(b)-4 | Priest Rapids Project Reasonable Portion Power Sales Contract executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development). |
| 10.7 | 1-3701 (with 2002 Form 10-K) | 10(b)-5 | Additional Product Sales Agreement (Priest Rapids Project) executed by Public Utility District No. 2 of Grant County, Washington and Avista Corporation dated December 12, 2001 (effective November 1, 2005 for the Priest Rapids Development and November 1, 2009 for the Wanapum Development). |
| 10.8 | 2-60728 | 5(g) | Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963. |
| 10.9 | 2-60728 | 5(g)-1 | Amendment to Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965. |
| 10.10 | 2-60728 | 5(h) | Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of September 18, 1963. |
| 10.11 | 2-60728 | 5(h)-1 | Amendment to Reserved Share Power Sales Contract (Wells Project) with Public Utility District No. 1 of Douglas County, Washington, dated as of February 9, 1965. |
| 10.12 | 1-3701 (with September 30, 1985 Form 10-Q) | 1 | Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company, dated as of September 17, 1985, describing the settlement of Project 3 litigation. |
| 10.13 | 1-3701 (with 1981 Form 10-K) | 10(s)-7 | Ownership and Operation Agreement for Colstrip Units No. 3 and 4, dated as of May 6, 1981. |
| 10.14 | 1-3701 (with 1992 Form 10-K) | 10(s)-1 | Agreements for Purchase and Sale of Firm Capacity between the Company and Portland General Electric Company dated March and June 1992. |
| 10.15 | 1-3701 (with 2003 Form 10-K) | 10(l) | Power Purchase and Sale Agreement between Avista Corporation and Potlatch Corporation, dated as of July 22, 2003. |
| 10.16 | 1-3701 (with June 30, 2007 Form 10-Q) | 10.1 | Indemnification Agreement entered into as of June 30, 2007 by Coral Energy Holding, L.P. and certain of its affiliates and Avista Energy, Inc. and certain of its affiliates. |
| 10.17 | 1-3701 (with June 30, 2007 Form 10-Q) | 10.2 | Guaranty Agreement effective as of June 30, 2007 entered into by Avista Capital, Inc. in favor of Coral Energy Holding, L.P. and certain of its affiliates. |
| 10.18 | 1-3701 (with 2008 Form 10-K) | 10.33 | Executive Deferral Plan of the Company.[3] |

| | Previously Filed [1] | | |
|---|---|---|---|
| Exhibit | With Registration Number | As Exhibit | |
| 10.19 | 1-3701 (with 2008 Form 10-K) | 10.34 | The Company's Unfunded Supplemental Executive Retirement Plan. [3] |
| 10.20 | 1-3701 (with 1992 Form 10-K) | 10(t)-11 | The Company's Unfunded Supplemental Executive Disability Plan. [3] |
| 10.21 | 1-3701 (with 2007 Form 10-K) | 10.34 | Income Continuation Plan of the Company. [3] |
| 10.22 | 1-3701 (with 2010 Definitive Proxy Statement filed March 31, 2010) | Appendix A | Avista Corporation Long-Term Incentive Plan. [3] |
| 10.23 | [2] | | Avista Corp. Performance Award Plan Summary. [3] |
| 10.24 | [2] | | Avista Corporation Performance Award Agreement. [3] |
| 10.25 | 1-3701 (with Form 8-K dated June 21, 2005) | 10.1 | Employment Agreement between the Company and Marian Durkin in the form of a Letter of Employment. [3] |
| 10.26 | 1-3701 (with Form 8-K dated August 13, 2008) | 10.1 | Employment Agreement between the Company and Mark T. Thies in the form of a Letter of Employment. [3] |
| 10.27 | 333-47290 | 99.1 | Non-Officer Employee Long-Term Incentive Plan. |
| 10.28 | [2] | | Form of Change of Control Agreement between the Company and its Executive Officers. [3][5][7] |
| 10.29 | [2] | | Form of Change of Control Agreement between the Company and its Executive Officers. [3][6][7] |
| 10.30 | [2] | | Form of Change of Control Agreement between the Company and its Executive Officers. [3][8] |
| 10.31 | [2] | | Form of Change of Control Agreement between the Company and its Executive Officers. [3][8] |
| 10.32 | [2] | | Avista Corporation Non-Employee Director Compensation. |
| 12 | [2] | | Statement Re: computation of ratio of earnings to fixed charges. |
| 21 | [2] | | Subsidiaries of Registrant. |
| 23 | [2] | | Consent of Independent Registered Public Accounting Firm. |

| | Previously Filed [1] | | |
|---|---|---|---|
| Exhibit | With Registration Number | As Exhibit | |
| 31.1 | [2] | | Certification of Chief Executive Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002). |
| 31.2 | [2] | | Certification of Chief Financial Officer (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002). |
| 32 | [4] | | Certification of Corporate Officers (Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002). |
| 101 | [4] | | The following financial information from the Annual Report on Form 10-K for the period ended December 31, 2010, formatted in XBRL (Extensible Business Reporting Language) and furnished electronically herewith: (i) the Consolidated Statements of Income; (ii) Consolidated Statements of Comprehensive Income; (iii) the Consolidated Balance Sheets; (iv) the Consolidated Statements of Cash Flows; (v) the Condensed Consolidated Statements of Equity and Redeemable Noncontrolling Interests; and (vi) the Notes to Consolidated Financial Statements, tagged as blocks of text. |

*(1) Incorporated herein by reference.*

*(2) Filed herewith.*

*(3) Management contracts or compensatory plans filed as exhibits to this Form 10-K pursuant to Item 15(b).*

*(4) Furnished herewith.*

*(5) Applies for Christy M. Burmeister-Smith, Don F. Kopczynski, James M. Kensok, David J. Meyer, Kelly O. Norwood, Richard L. Storro, Jason R. Thackston, Dennis P. Vermillion, and Roger D. Woodworth.*

*(6) Applies for Marian M. Durkin, Karen S. Feltes, Scott L. Morris, and Mark T. Thies.*

*(7) The plans were modified to comply with Section 409A of the Internal Revenue Code. No significant changes were made to the plans.*

*(8) Applies to executive officers appointed to their positions after October 1, 2010. The Company does not currently have any officers that these agreements apply to.*

# EXHIBIT 12

*Avista Corporation*
*Computation of Ratio of Earnings to Fixed Charges*
*Consolidated*
*(Thousands of Dollars)*
*Years Ended December 31,*

| | 2010 | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| Fixed charges, as defined: | | | | | |
| Interest charges | $ 72,010 | $ 61,361 | $ 74,914 | $ 80,095 | $ 88,426 |
| Amortization of debt expense and premium — net | 4,414 | 5,673 | 4,673 | 6,345 | 7,741 |
| Interest portion of rentals | 2,027 | 1,874 | 1,601 | 1,612 | 1,802 |
| Total fixed charges | $ 78,451 | $ 68,908 | $ 81,188 | $ 88,052 | $ 97,969 |
| Earnings, as defined: | | | | | |
| Pre-tax income from continuing operations | $ 146,105 | $ 134,971 | $ 120,382 | $ 63,061 | $ 114,927 |
| Add (deduct): | | | | | |
| Capitalized interest | (298) | (545) | (4,612) | (3,864) | (2,934) |
| Total fixed charges above | 78,451 | 68,908 | 81,188 | 88,052 | 97,969 |
| Total earnings | $ 224,258 | $ 203,334 | $ 196,958 | $ 147,249 | $ 209,962 |
| Ratio of earnings to fixed charges | 2.86 | 2.95 | 2.43 | 1.67 | 2.14 |

*Avista Corporation*

## SUBSIDIARIES OF REGISTRANT

| Subsidiary | State or Country of Incorporation |
|---|---|
| Avista Capital, Inc. | Washington |
| Advantage IQ, Inc. | Washington |
| Avista Development, Inc. | Washington |
| Avista Energy, Inc. | Washington |
| Avista Northwest Resources, LLC | Washington |
| Avista Power, LLC | Washington |
| Avista Turbine Power, Inc. | Washington |
| Avista Ventures, Inc. | Washington |
| Pentzer Corporation | Washington |
| Pentzer Venture Holding II, Inc. | Washington |
| Bay Area Manufacturing, Inc. | Washington |
| Advanced Manufacturing and Development, Inc. | California |
| Avista Receivables Corporation | Washington |
| Avista Capital II | Delaware |
| Spokane Energy, LLC | Delaware |
| Steam Plant Square, LLC | Washington |
| Steam Plant Brew Pub, LLC | Washington |
| Courtyard Office Center, LLC | Washington |
| Ecos IQ, Inc. | Washington |

## CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 2-81697, 2-94816, 033-54791, 333-03601, 333-22373, 333-58197, 333-33790, 333-47290, and 333-126577 on Form S-8; and in Registration Statement Nos. 033-53655, 333-63243, 333-64652, 333-155657, and 333-163609 on Form S-3 of our reports dated February 25, 2011, relating to the consolidated financial statements of Avista Corporation and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of Accounting Standards Update No. 2009-17, *Consolidations — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities)*, and the effectiveness of Avista Corporation's and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Avista Corporation for the year ended December 31, 2010.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 25, 2011

## EXHIBIT 31.1

### CERTIFICATION

I, Scott L. Morris, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2011

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

## EXHIBIT 31.2

### CERTIFICATION

I, Mark T. Thies, certify that:

1. I have reviewed this report on Form 10-K of Avista Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2011

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

## EXHIBIT 32

*Avista Corporation*

### CERTIFICATION OF CORPORATE OFFICERS

*(Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002)*

Each of the undersigned, Scott L. Morris, Chairman of the Board, President and Chief Executive Officer of Avista Corporation (the "Company"), and Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Company's Annual Report on Form 10-K for the year ended December 31, 2010 fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and that the information contained therein fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2011

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

/s/ Mark T. Thies
Mark T. Thies
Senior Vice President and
Chief Financial Officer

*Avista Corporation*
*As of and for the years ended December 31,*
*Dollars in thousands, except per share data and ratios*

| | 2010 | 2009 | 2008 | 2007 | 2006 | 2000 |
|---|---|---|---|---|---|---|
| **Financial Results** | | | | | | |
| Operating revenues | $ 1,558,740 | $ 1,512,565 | $ 1,676,763 | $ 1,417,757 | $ 1,506,311 | $ 1,935,479 |
| Operating expenses | 1,328,552 | 1,311,907 | 1,491,852 | 1,279,328 | 1,306,751 | 1,706,449 |
| Income from operations | 230,188 | 200,658 | 184,911 | 138,429 | 199,560 | 229,030 |
| Interest expense | 76,424 | 67,034 | 79,587 | 86,440 | 96,167 | 68,255 |
| Income taxes | 51,157 | 46,323 | 45,625 | 24,334 | 41,986 | 81,143 |
| Income from continuing operations | 94,948 | 88,648 | 74,757 | 38,727 | 72,941 | 109,065 |
| Loss from discontinued operations | — | — | — | — | — | (17,386) |
| Net income | 94,948 | 88,648 | 74,757 | 38,727 | 72,941 | 91,679 |
| Net income attributable to noncontrolling interests | (2,523) | (1,577) | (1,137) | (252) | — | — |
| Preferred stock dividend requirements [1] | — | — | — | — | — | 23,735 |
| Net income attributable to Avista Corporation | $ 92,425 | $ 87,071 | $ 73,620 | $ 38,475 | $ 72,941 | $ 67,944 |
| Earnings per common share attributable to Avista Corporation, diluted: | | | | | | |
| Earnings from continuing operations | $ 1.65 | $ 1.58 | $ 1.36 | $ 0.72 | $ 1.46 | $ 1.85 |
| Loss from discontinued operations | — | — | — | — | — | (0.38) |
| Total | $ 1.65 | $ 1.58 | $ 1.36 | $ 0.72 | $ 1.46 | $ 1.47 |
| Earnings per common share attributable to Avista Corporation, basic: | $ 1.66 | $ 1.59 | $ 1.37 | $ 0.73 | $ 1.48 | $ 1.49 |
| **Common Stock Statistics** | | | | | | |
| Dividends paid per common share | $ 1.00 | $ 0.81 | $ 0.69 | $ 0.595 | $ 0.57 | $ 0.48 |
| Book value per common share | $ 19.71 | $ 19.17 | $ 18.30 | $ 17.27 | $ 17.41 | $ 15.34 |
| Shares of common stock: | | | | | | |
| Outstanding at year-end | 57,120 | 54,837 | 54,488 | 52,909 | 52,514 | 47,209 |
| Average — basic | 55,595 | 54,694 | 53,637 | 52,796 | 49,162 | 45,690 |
| Average — diluted | 55,824 | 54,942 | 54,028 | 52,263 | 49,897 | 46,103 |
| Return on average Avista Corporation stockholders' equity: | | | | | | |
| Total company | 8.5% | 8.5% | 7.7% | 4.2% | 8.7% | 12.9% |
| Utility only | 8.6% | 9.2% | 8.0% | 5.8% | 9.6% | -23.7% |
| Non-utility only | 7.2% | 0.4% | 4.9% | -3.4% | 6.2% | 44.1% |
| Common stock price: | | | | | | |
| High | $ 22.81 | $ 22.44 | $ 23.30 | $ 25.81 | $ 27.52 | $ 68.00 |
| Low | $ 18.46 | $ 12.67 | $ 16.58 | $ 18.19 | $ 17.61 | $ 14.63 |
| Year-end close | $ 22.52 | $ 21.59 | $ 19.38 | $ 21.54 | $ 25.31 | $ 20.50 |

*(1) Preferred stock was reclassified from equity to liabilities in 2003 in accordance with a change in accounting standards. Accordingly, preferred stock dividend requirements were reclassified to interest expense effective July 1, 2003. Balance includes current portion.*

*Avista Corporation*
*As of and for the years ended December 31,*
*Dollars in thousands, except per share data and ratios*

| | 2010 | 2009 | 2008 | 2007 | 2006 | 2000 |
|---|---|---|---|---|---|---|
| **Debt and Preferred Stock Statistics** | | | | | | |
| Pretax interest coverage: | | | | | | |
| Including AFUDC/AFUCE | 2.96(x) | 2.97(x) | 2.45(x) | 1.75(x) | 2.11(x) | 2.35(x) |
| Excluding AFUDC/AFUCE | 2.91(x) | 2.92(x) | 2.32(x) | 1.65(x) | 2.06(x) | 2.32(x) |
| Embedded cost of long-term debt | 5.76% | 5.91% | 6.69% | 7.84% | 7.79% | 7.40% |
| Embedded cost of preferred stock | — % | — % | — % | — % | 7.39% | 7.39% |
| **Financial Condition** | | | | | | |
| Total assets | $ 3,940,095 | $ 3,606,959 | $ 3,630,747 | $ 3,189,797 | $ 4,056,508 | $ 12,739,511 |
| Total net utility property | 2,714,237 | 2,607,011 | 2,492,191 | 2,351,342 | 2,215,037 | 1,680,742 |
| Utility property capital expenditures (excluding equity-related AFUDC) | 202,227 | 205,384 | 219,239 | 205,811 | 161,266 | 98,680 |
| Long-term debt (including current portion) | 1,101,857 | 1,071,338 | 826,465 | 948,833 | 976,459 | 679,806 |
| Nonrecourse long-term debt of Spokane Energy (including current portion) [2] | 58,934 | — | — | — | — | — |
| Long-term debt to affiliated trusts | 51,547 | 51,547 | 113,403 | 113,403 | 113,403 | 100,000 |
| Preferred stock subject to mandatory redemption [1] | — | — | — | — | 26,250 | 35,000 |
| Avista Corporation stockholders' equity | $ 1,125,784 | $ 1,051,287 | $ 996,883 | $ 913,966 | $ 914,525 | $ 724,224 |

*(1) Preferred stock was reclassified from equity to liabilities in 2003 in accordance with a change in accounting standards. Accordingly, preferred stock dividend requirements were reclassified to interest expense effective July 1, 2003. Balance includes current portion.*

*(2) Spokane Energy was consolidated effective January 1, 2010. See Note 2 of the Notes to Consolidated Financial Statements.*

*Avista Corporation*
*As of and for the years ended December 31,*

| | 2010 | 2009 | 2008 | 2007 | 2006 | 2000 |
|---|---|---|---|---|---|---|
| **Avista Utilities** | | | | | | |
| **Electric Operations** | | | | | | |
| Electric operating revenues (millions of dollars): | | | | | | |
| Residential | $ 296.6 | $ 315.7 | $ 279.6 | $ 251.4 | $ 234.7 | $ 158.1 |
| Commercial | 265.2 | 274.0 | 247.7 | 224.2 | 221.2 | 149.8 |
| Industrial | 114.8 | 107.7 | 101.8 | 95.2 | 92.9 | 83.0 |
| Public street and highway lighting | 6.7 | 6.6 | 6.0 | 5.5 | 5.3 | 3.6 |
| Total retail | 683.3 | 704.0 | 635.1 | 576.3 | 554.1 | 394.5 |
| Wholesale | 165.6 | 88.4 | 141.8 | 105.7 | 126.2 | 864.7 |
| Sales of fuel | 106.4 | 33.0 | 44.7 | 12.9 | 48.2 | 1.3 |
| Other | 19.0 | 15.4 | 16.9 | 16.2 | 18.9 | 26.8 |
| Total electric operating revenues | $ 974.3 | $ 840.8 | $ 838.5 | $ 711.1 | $ 747.4 | $ 1,287.3 |
| Electric energy sales (millions of kWhs): | | | | | | |
| Residential | 3,618 | 3,791 | 3,744 | 3,670 | 3,578 | 3,279 |
| Commercial | 3,100 | 3,177 | 3,188 | 3,132 | 3,110 | 2,886 |
| Industrial | 2,099 | 1,948 | 2,059 | 2,084 | 2,062 | 2,048 |
| Public street and highway lighting | 26 | 26 | 26 | 26 | 25 | 25 |
| Total retail | 8,843 | 8,942 | 9,017 | 8,912 | 8,775 | 8,238 |
| Wholesale | 3,803 | 2,354 | 1,964 | 1,594 | 2,117 | 15,807 |
| Total electric energy sales | 12,646 | 11,296 | 10,981 | 10,506 | 10,892 | 24,045 |
| Retail electric customers (average per year): | | | | | | |
| Residential | 315,283 | 313,884 | 311,381 | 306,737 | 300,940 | 273,219 |
| Commercial | 39,489 | 39,276 | 39,075 | 38,488 | 37,912 | 35,060 |
| Industrial | 1,376 | 1,394 | 1,388 | 1,378 | 1,388 | 1,254 |
| Public street and highway lighting | 449 | 444 | 434 | 426 | 425 | 392 |
| Total retail electric customers | 356,597 | 354,998 | 352,278 | 347,029 | 340,665 | 309,925 |
| Retail electric customers (at year-end): | | | | | | |
| Residential | 317,451 | 315,297 | 313,660 | 310,701 | 305,293 | 276,382 |
| Commercial | 39,619 | 39,408 | 39,173 | 39,001 | 38,362 | 35,109 |
| Industrial | 1,372 | 1,384 | 1,384 | 1,383 | 1,378 | 1,398 |
| Public street and highway lighting | 453 | 447 | 440 | 427 | 417 | 401 |
| Total retail electric customers | 358,895 | 356,536 | 354,657 | 351,512 | 345,450 | 313,290 |
| Revenue per residential kWh (cents) | 8.20 | 8.33 | 7.47 | 6.85 | 6.56 | 4.82 |
| Use per residential customer (kWh) | 11,476 | 12,079 | 12,023 | 11,965 | 11,888 | 12,003 |
| Revenue per commercial kWh (cents) | 8.56 | 8.62 | 7.77 | 7.16 | 7.11 | 5.19 |
| Use per commercial customer (kWh) | 78,507 | 80,881 | 81,583 | 81,377 | 82,028 | 82,311 |
| Electric energy resources (millions of kWhs): | | | | | | |
| Hydro generation (from Company facilities) | 3,494 | 3,766 | 3,851 | 3,689 | 4,128 | 3,819 |
| Thermal generation (from Company facilities) | 3,748 | 3,097 | 3,693 | 3,640 | 3,434 | 3,154 |
| Purchased power — long-term hydro contracts | 685 | 839 | 833 | 861 | 787 | 929 |
| Purchased power — wholesale | 5,315 | 4,152 | 3,253 | 2,959 | 3,101 | 16,706 |
| Power exchanges | (15) | (18) | (17) | (18) | 35 | 67 |
| Total power resources | 13,227 | 11,836 | 11,613 | 11,131 | 11,485 | 24,675 |
| Energy losses and company use | (581) | (540) | (632) | (625) | (593) | (630) |
| Total electric energy resources | 12,646 | 11,296 | 10,981 | 10,506 | 10,892 | 24,045 |

*Avista Corporation*
*As of and for the years ended December 31,*

| | 2010 | 2009 | 2008 | 2007 | 2006 | 2000 |
|---|---|---|---|---|---|---|
| **Electric Operations (continued)** | | | | | | |
| Total resources available at peak (MW): | | | | | | |
| Company owned: | | | | | | |
| Hydro | 716 | 562 | 765 | 617 | 980 | 956 |
| Thermal | 821 | 781 | 724 | 830 | 837 | 586 |
| Purchased power: | | | | | | |
| Long-term hydro contracts | 152 | 103 | 132 | 171 | 143 | 184 |
| Other | 1,216 | 1,068 | 859 | 684 | 658 | 2,468 |
| Total resources available at peak (winter) | 2,905 | 2,514 | 2,480 | 2,302 | 2,618 | 4,194 |
| Net system peak demand (winter) | 1,704 | 1,763 | 1,821 | 1,685 | 1,656 | 1,491 |
| Wholesale obligations | 803 | 608 | 562 | 367 | 431 | 2,338 |
| Total requirements (winter) | 2,507 | 2,371 | 2,383 | 2,052 | 2,087 | 3,829 |
| Reserve margin | 14% | 6% | 4% | 11% | 20% | 9% |
| Annual load factor | 60% | 61% | 62% | 61% | 59% | 68% |
| **Natural Gas Operations** | | | | | | |
| Natural gas operating revenues (millions of dollars): | | | | | | |
| Residential | $ 193.2 | $ 251.0 | $ 276.4 | $ 264.5 | $ 257.8 | $ 128.2 |
| Commercial | 98.2 | 135.2 | 152.1 | 148.4 | 146.6 | 70.0 |
| Industrial and interruptible | 6.5 | 10.0 | 12.2 | 11.3 | 11.7 | 7.7 |
| Total retail | 297.9 | 396.2 | 440.7 | 424.2 | 416.1 | 205.9 |
| Wholesale | 197.3 | 143.5 | 281.7 | 142.2 | 93.2 | 5.7 |
| Transportation | 6.5 | 6.1 | 6.3 | 6.6 | 6.5 | 10.2 |
| Other | 9.5 | 8.6 | 5.5 | 4.2 | 4.8 | 3.0 |
| Total natural gas operating revenues | $ 511.2 | $ 554.4 | $ 734.2 | $ 577.2 | $ 520.6 | $ 224.8 |
| Natural gas therms delivered (millions of therms): | | | | | | |
| Residential | 188.5 | 208.0 | 210.1 | 195.7 | 192.8 | 212.2 |
| Commercial | 113.4 | 126.3 | 128.2 | 121.6 | 121.0 | 135.1 |
| Industrial and interruptible | 9.8 | 10.9 | 12.2 | 10.8 | 11.0 | 18.3 |
| Total retail | 311.7 | 345.2 | 350.5 | 328.1 | 324.8 | 365.6 |
| Wholesale | 468.9 | 398.0 | 345.9 | 223.1 | 154.9 | 4.0 |
| Transportation and other | 142.5 | 145.1 | 149.3 | 149.2 | 150.2 | 226.3 |
| Total natural gas therms delivered | 923.1 | 888.3 | 845.7 | 700.4 | 629.9 | 595.9 |
| Retail natural gas customers (average per year): | | | | | | |
| Residential | 282,721 | 280,667 | 277,892 | 273,415 | 267,345 | 242,983 |
| Commercial | 33,431 | 33,214 | 32,901 | 32,327 | 31,746 | 29,739 |
| Industrial and interruptible | 292 | 300 | 297 | 302 | 295 | 334 |
| Total retail natural gas customers | 316,444 | 314,181 | 311,090 | 306,044 | 299,386 | 273,056 |
| Retail natural gas customers (at year-end): | | | | | | |
| Residential | 285,067 | 282,538 | 280,687 | 277,397 | 272,109 | 248,418 |
| Commercial | 33,638 | 33,369 | 33,123 | 32,840 | 32,173 | 30,138 |
| Industrial and interruptible | 291 | 294 | 292 | 298 | 304 | 332 |
| Total retail natural gas customers | 318,996 | 316,201 | 314,102 | 310,535 | 304,586 | 278,888 |

*Avista Corporation*
*As of and for the years ended December 31,*

| | 2010 | 2009 | 2008 | 2007 | 2006 | 2000 |
|---|---|---|---|---|---|---|
| **Natural Gas Operations (continued)** | | | | | | |
| Revenue per residential therm (in dollars) | 1.02 | 1.21 | 1.32 | 1.35 | 1.34 | 0.60 |
| Use per residential customer (therms) | 667 | 741 | 756 | 716 | 721 | 873 |
| Revenue per commercial therm (in dollars) | 0.87 | 1.07 | 1.19 | 1.22 | 1.21 | 0.52 |
| Use per commercial customer (therms) | 3,393 | 3,804 | 3,897 | 3,760 | 3,811 | 4,544 |
| Heating degree days (at Spokane, Washington): | | | | | | |
| Actual | 6,320 | 6,976 | 7,052 | 6,539 | 6,332 | 7,176 |
| 30 year average | 6,647 | 6,820 | 6,820 | 6,820 | 6,820 | 6,842 |
| Actual as a percent of average | 95% | 102% | 103% | 96% | 93% | 105% |
| **Advantage IQ** | | | | | | |
| Revenues (millions of dollars) | $ 102.0 | $ 77.3 | $ 59.1 | $ 47.3 | $ 39.6 | $ 5.0 |
| Total assets (millions of dollars) | $ 221.1 | $ 143.1 | $ 125.9 | $ 108.9 | $ 100.4 | $ 11.1 |
| **Other** | | | | | | |
| Revenues (millions of dollars) | $ 61.1 | $ 40.1 | $ 45.0 | $ 82.1 | $ 198.7 | $ 579.8 |
| Total assets (millions of dollars) | $ 129.8 | $ 63.5 | $ 70.0 | $ 71.4 | $ 1,060.2 | $ 10,368.2 |

# CORPORATE **INFORMATION**

**COMPANY HEADQUARTERS**
Spokane, Washington

**AVISTA ON THE INTERNET**
Financial results, stock quotes, news releases, documents filed with the Securities and Exchange Commission, and information on the company's products and services are available on Avista's Web site at www.avistacorp.com.

**TRANSFER AGENT**
BNY Mellon is the company's stock transfer, dividend payment and reinvestment plan agent. Answers to many shareholder questions and requests for forms are available by visiting its Web site at www.bnymellon.com/shareowner/isd

**STOCK INQUIRIES SHOULD BE DIRECTED TO:**
Avista Corp.
c/o BNY Mellon Shareowner Services
P.O. Box 358035
Pittsburgh, PA 15252-8035
800.642.7365
e-mail: shrrelations@bnymellon.com

**INVESTOR INFORMATION**
A copy of the company's financial reports, including the reports on Forms 10-K and 10-Q filed with the Securities and Exchange Commission, will be provided without charge upon request to:
Avista Corp.
Investor Relations
P.O. Box 3727 MSC-19
Spokane, WA 99220-3727
800.222.4931

**ANNUAL MEETING OF SHAREHOLDERS**
Shareholders are invited to attend the company's annual meeting to be held at 8:15 a.m. PDT on Thursday, May 12, 2011, at Avista Corp. headquarters, 1411 East Mission Avenue, Spokane, Washington.

The annual meeting also will be webcast. Please go to www.avistacorp.com to preregister for the webcast and to listen to the live webcast. The webcast will be archived at www.avistacorp.com for one year to allow shareholders to listen at their convenience.

**EXCHANGE LISTING**
Ticker Symbol: AVA
New York Stock Exchange

**CERTIFICATIONS**
On May 28, 2010, the Chief Executive Officer (CEO) of Avista Corp. filed a Section 303A.12(a) Annual CEO Certification with the New York Stock Exchange. The CEO Certification attests that the CEO is not aware of any violations by the company of NYSE's Corporate Governance Listing Standards.

Avista Corp. has included as exhibits to its annual report on Form 10-K for the year 2010, filed with the Securities and Exchange Commission, certifications of Avista's Chief Executive Officer and Chief Financial Officer regarding the quality of Avista's public disclosure in compliance with Section 302 of the Sarbanes-Oxley Act of 2002.

This annual report contains forward-looking statements regarding the company's current expectations. These statements are subject to a variety of risks and uncertainties that could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all factors discussed in the company's annual report on Form 10-K for the year 2010. Our 2010 annual report is provided for shareholders. It is not intended for use in connection with any sale or purchase of or any solicitation of others to buy or sell securities.



The 2010 annual report is produced through a partnership of talented employees and companies within Avista's service area.
Many thanks for their assistance.
Klündt | Hosmer, J. Craig Sweat Photography, Dean Davis Photography, Hamilton Studio, Cutaway Media and Lawton Printing.

# HELP US HELP THE **ENVIRONMENT**

Managing costs is a primary goal for Avista. You can help us meet this goal by agreeing to receive future annual reports and proxy statements electronically. This service saves on the costs of printing and mailing, provides timely delivery of information, and helps protect our environment by saving energy and decreasing the need for paper, printing and mailing materials. For more information, please visit our Web site www.avistacorp.com.

*In our commitment to sustainability, the forest products used in the 2010 annual report are FSC certified – sustainably harvested from the forest of origin and responsibly managed through the supply chain.*

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