2008 ANNUAL REPORT

THE **POWER** BEHIND GREEN THINKING

AVISTA Corp.

TABLE OF CONTENTS

CELEBRATING 25 YEARS OF CLEAN ELECTRICITY

In 2008 we celebrated the 25th anniversary of our Kettle Falls generating plant, the first facility built in this country for the sole purpose of generating power with biomass. The plant replaced air-polluting wigwam burners and effectively turns sawmill waste and forest slash into clean, renewable electricity, producing enough energy to power a community of 40,000 homes.

NOXON RAPIDS DAM. This year's annual report cover communicates the power of renewable energy generation. This unique perspective of Avista's Noxon Rapids dam conveys the force and importance of renewable resources such as water power and their importance to Avista's diverse resource mix.

RENEWABLE ENERGY **GENERATION**

SCOTT L. MORRIS
Chairman, President and
Chief Executive Officer

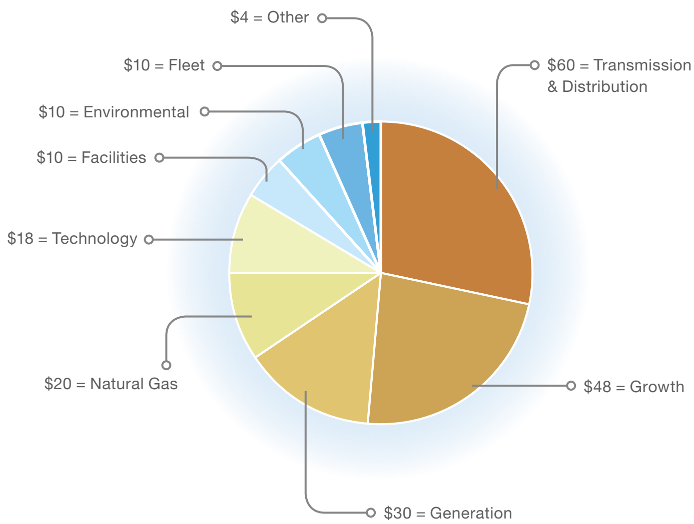
TO MY FELLOW SHAREHOLDERS:

Imagine a place where "renewable" is not a buzzword or a mandate but a critical part of a utility's energy generation resources. We did, starting in 1889 – long before it was cool to be green. Today, among America's 100 largest utilities, Avista Utilities – our core business – has one of the smallest carbon footprints among those that are investor-owned. We are committed to this tradition of environmental stewardship and efficient use of resources. It's our best way to provide our customers the safe, reliable energy they expect for their lives. It is the power behind green thinking.

To continue this legacy of service, we have steadily been implementing strategies to strengthen Avista's financial health. Our primary focus has been on improving the strategic alignment of our investments to assure a reliable utility and to establish new platforms for growth in the future. At the same time, we are vigilant in managing the prudent use of funds as costs are rapidly escalating for materials, healthcare and pension expenses, among others.

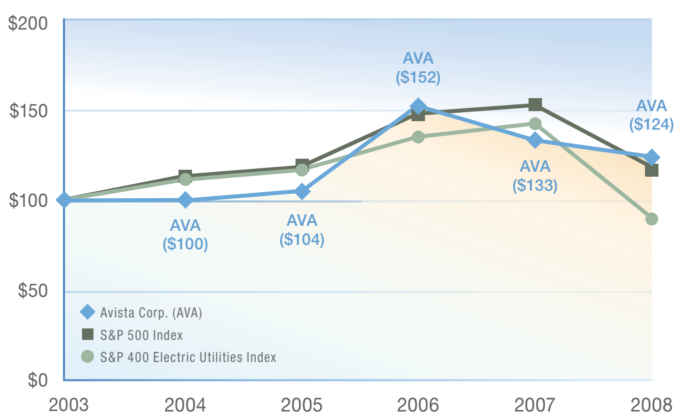
Returning Avista's credit rating to investment grade was a goal we set following the energy crisis of 2000-2001. We achieved that in 2008. Now our focus is to operate at a level that will support a stronger corporate credit rating of BBB/BBB+, improving on the rating of BBB- where we currently stand. Operating at this level will help reduce long-term debt costs, benefitting both investors and customers.

2009 CAPITAL BUDGET / Total Capital Budget $210 ($ in millions)

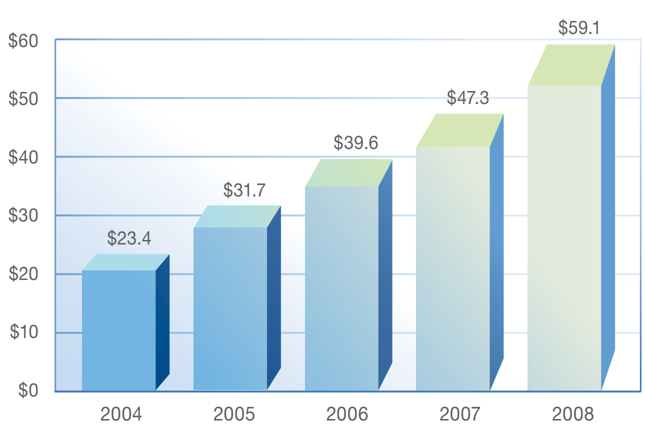


TOTAL RETURN TO SHAREHOLDERS

(includes reinvestment of dividends)



ADVANTAGE IQ REVENUES / 2004 — 2008 ($ in millions)



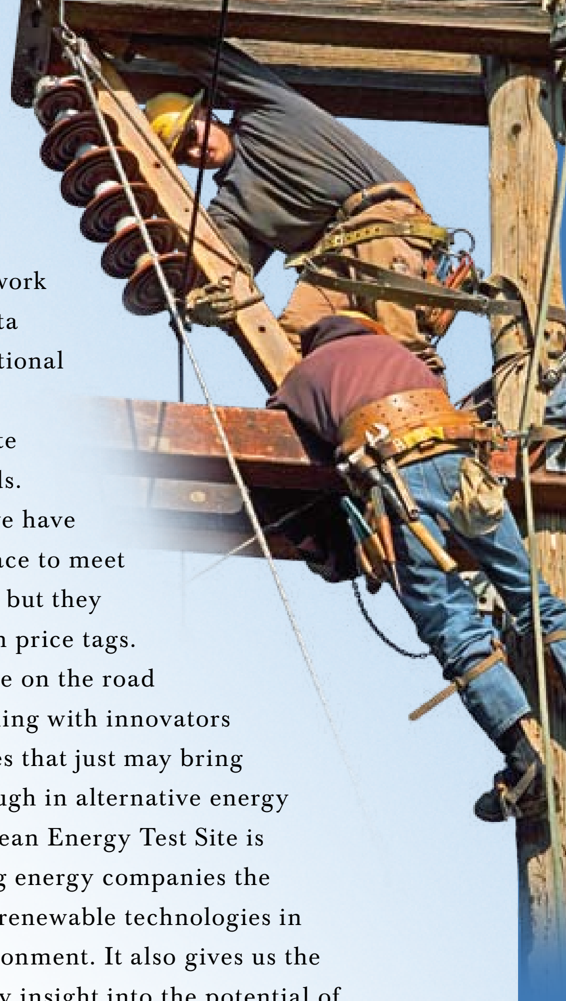
Along the way, we have continued to increase shareholder value. In 2008 our board of directors increased the dividend twice for a total of 20 percent, from $0.15 to $0.18 per share per quarter. We intend to recommend to the board of directors that our dividend continues to grow so as to be more in line with the utility industry average of 60 percent to 70 percent of earnings.

Despite the volatility in the financial markets, we executed some new, reasonably priced debt and credit transactions during 2008. With these agreements in place we have the flexibility and liquidity we need to meet our current obligations.

I'm pleased to report that Advantage IQ – our subsidiary that provides facility information and cost-management services to multi-site companies – continues its growth. Customer demand for its highly valued services plus its 2008 acquisition of Cadence Network have resulted in a more robust company. With an expanded pool of expertise and services, the company is helping its clients identify and implement sustainable and environmentally sound energy management practices. As a result Advantage IQ is well-positioned to continue its growth, possibly leading to a monetization event in the next few years.

Avista – and the utility sector as a whole – is in a cycle of significant capital spending to meet the need for upgraded generation, transmission and distribution facilities, maintenance and replacement of natural gas systems, and increasing environmental compliance standards. Our planning has identified the need for the company to make significant expenditures over the next 20 years, including investments in wind and other alternative energy resources. Nearly $210 million of capital expenditures are planned for both 2009 and 2010. In addition, we'll incur major costs associated with relicensing our Spokane River hydroelectric facilities, which

INVESTING IN OUR INFRASTRUCTURE. In addition to investing in new and alternative energy resources, Avista is upgrading and enhancing existing electric transmission and distribution systems and natural gas pipelines.



is likely to occur in 2009, following a 2008 landmark settlement agreement with the Coeur d'Alene Tribe.

These investments are essential to increase system capacity, enhance the reliability of the energy we provide and expand our system to meet customer growth. Infrastructure upgrades will also include technology enhancements that will eventually enable two-way communications and integrate our customer relationships with smart grid technology.

The timely recovery of costs like these is essential to the financial strength of our company and to give every customer useful information about the true cost of energy. We implemented new electric and natural gas base rates in Washington, Idaho and Oregon in 2008. And our projections show additional price adjustments will be needed in each of the next few years to recover our increased investments, as well as to more closely align our rates of return with those allowed by regulators.

As demand for energy continues to grow, our commitment is to meet that demand reliably, responsibly and cost-effectively. But new energy comes at a price. While renewable and alternative energy will continue to play an increasingly important role in our future, building new sources of generation is costly. We know that the lowest cost "new" resource is energy efficiency. That's why we have been helping our customers understand and use energy efficiently for nearly three decades.

Climate change is at the forefront of many of today's public policy debates. And the devil will be in the details of how cap and trade legislation or other mandates will be finalized. We believe that the acknowledgement of legacy hydroelectric and biomass generation plants must be an important consideration. So, we are active participants in helping to shape the legislation.

There is also work still ahead for Avista to acquire the additional resources needed to meet current state renewable standards. We are confident we have the strategies in place to meet these expectations, but they will come with high price tags.

Keeping an eye on the road ahead, we are working with innovators to pilot technologies that just may bring the next breakthrough in alternative energy generation. Our Clean Energy Test Site is providing emerging energy companies the chance to test new renewable technologies in a utility scale environment. It also gives us the chance to gain early insight into the potential of such devices for serving our own customers.

The power behind green thinking. It's happening daily at Avista. Our talented employees are working to find ways of using technology that further streamline operations; to reuse and recycle all we can; to create and to put in operation innovative ways of providing the energy our customers want in ways that are cost effective and sustainable for the future; and to continue our nationally recognized legacy of being good stewards of our environment.

We will continue to stay the course we have set for ourselves – delivering excellent service to our customers, making prudent and strategic investments in energy systems, and earning a fair return for you, the investors who enable all that we do. Thank you.

Scott Morris

SCOTT L. MORRIS
Chairman, President and Chief Executive Officer

THE **POWER** BEHIND GREEN THINKING

The beauty and power of the natural resources in the Northwest abound. Our job as an energy provider is to put those resources to work in wise ways, in service to our customers and their communities. We're doing exactly that.

It begins with our resource planning – developing the most efficient, diverse and best-cost mix of generating resources to provide our customers the safe, reliable, cost-effective energy they need. Today, we're upgrading current hydroelectric generation capacities. Looking forward, we've secured the rights to develop renewable wind power within our service territory, close to our own transmission lines, to complement that which we now get from wind power contracts. Purposeful actions. Sustainable thinking.

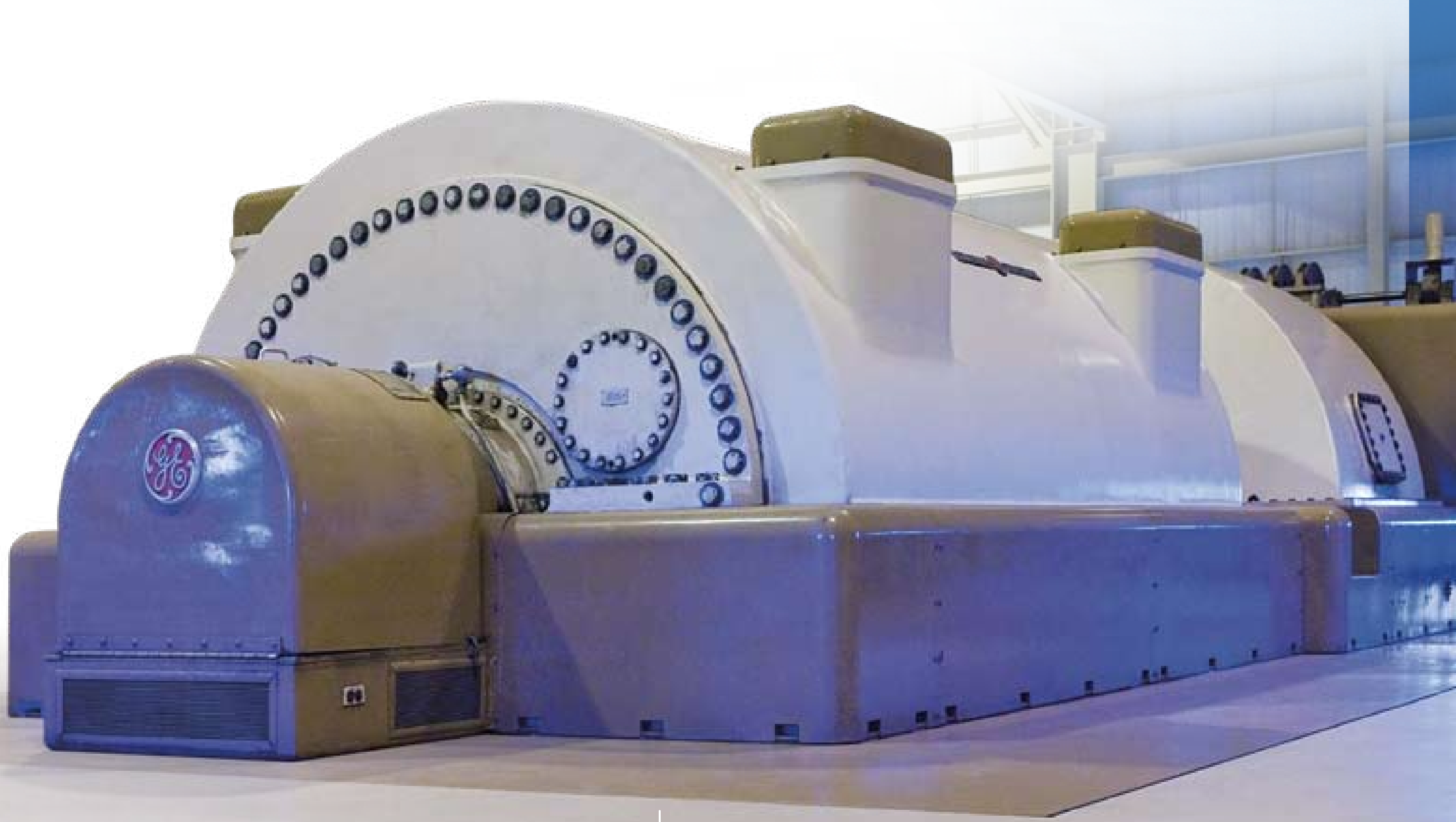
Hydro – Nature's power in action

Avista's largest hydroelectric plant, Noxon Rapids, went on line in 1959 and is situated on the Clark Fork River in western Montana. After 50 years of reliable service, the plant is undergoing upgrades to four of its five generating units. When these are completed in 2012, Noxon Rapids will add 30 megawatts of capacity for a total of 557 megawatts of renewable power. As part of our commitment to the environment, we are long-time partners with state and federal fish and wildlife agencies to protect the aquatic resources in the Clark Fork River. And we've invested millions of dollars to conserve wetlands, protect fish habitat and enhance recreational access along the river through Montana and Idaho.

Biomass – Energy grows

The forests of the Northwest are rich resources of timber. But milling lumber leads to tons of wasted wood scraps. Avista's Kettle Falls generating plant takes that waste – hog fuel – and uses it to generate power cleanly and efficiently. The first plant in this country constructed solely to generate power using biomass fuel, Kettle Falls plays an important role in reusing wood waste from lumber mills and slash from fire prevention forest clearing operations to generate 50 megawatts of power – a sustainable energy resource.

KETTLE FALLS GENERATING PLANT. This large turbine within Avista's Kettle Falls generating plant produces clean energy from sawmill waste and forest slash.



BRINGING NATURAL GAS TO NEW CUSTOMERS. Through Avista's efforts to extend natural gas mains into communities – like Sagle, Idaho – more rural customers are enjoying this efficient, reliable source of energy

Natural Gas – Safe, clean, reliable

Natural gas is the cleanest and most efficient fossil fuel. It is an important part of our clean energy resource mix. In 2008 we extended our natural gas pipelines into more communities and worked with developers of over 500 multi-family housing units to install this highly efficient source of energy.

For example, bringing natural gas to Sagle, Idaho, means residents of this growing rural community no longer have to worry whether the propane truck will reach their home to keep their tanks full. More importantly, they now have peace of mind knowing that their supply of natural gas for heating, cooking and washing is highly reliable. In addition, they get more value for their energy dollar, because using natural gas in the home with high efficiency appliances more than doubles the energy efficiency of using natural gas to produce electricity used in homes.

NATURAL GAS IN OREGON. Avista is extending natural gas to urban and suburban customers in Oregon, as well as in Washington and Idaho.

PUTTING **GREEN THINKING** TO WORK

Energy Efficiency – demand-side management (DSM) – remains the lowest cost new resource, and it benefits everyone. Our customers are increasingly interested in implementing changes to their life styles and business practices that positively impact the way they use energy every day.

Through Avista-sponsored programs, our customers in Washington, Idaho and Oregon reduced their energy use in 2008 by more than 66.5 million kilowatt-hours of electricity and over 2.2 million therms of natural gas. That's enough savings to provide energy to more than 6,300 homes and businesses in our region for one year. To help customers achieve those savings we provided more than 18,000 rebates and incentives, totaling over $15 million to residential and commercial customers. Funding for this program comes from a small DSM surcharge on customer bills, the first funding mechanism of its type in the country.

AT HOME WITH AVISTA

You can build houses like you've always built them or you can build them in ways that are better for the environment and energy efficient, too. We've joined with Inland Northwest Built Green® to train builders in using construction principles, materials and techniques that conserve natural resources, while protecting our environment. Integrating energy efficiency and environmental sustainability into new construction from the ground up helps our customers get more value from their energy dollar, while conserving resources through waste reduction and recycling. Forty-five builders, developers, vendors and suppliers have committed to participating in the program, and 26 homes were certified as Built Green® in the first seven months of the program's launch in 2008.

What is it about kids and their ability to get adults to pay attention? When we saw the need to make it easier for families to make lifestyle changes to help manage their energy costs, we knew a good way to reach them was to get the attention of their children. Wattson, Avista's Energy Watchdog, interacts with kids at community events, on television and on his own website (www.avistakids.com). His appeal and his message are simple and universal – turn off the light when leaving a room, put on a sweater when it's cold and take shorter showers to save hot water. In 2008 Wattson appeared at over 40 community events, touching the lives of more than 25,000 children and families. Our region's kids are learning to be wise users of our precious resources, and they are sharing this knowledge with their families, friends and neighbors.

Visit Wattson at www.avistakids.com

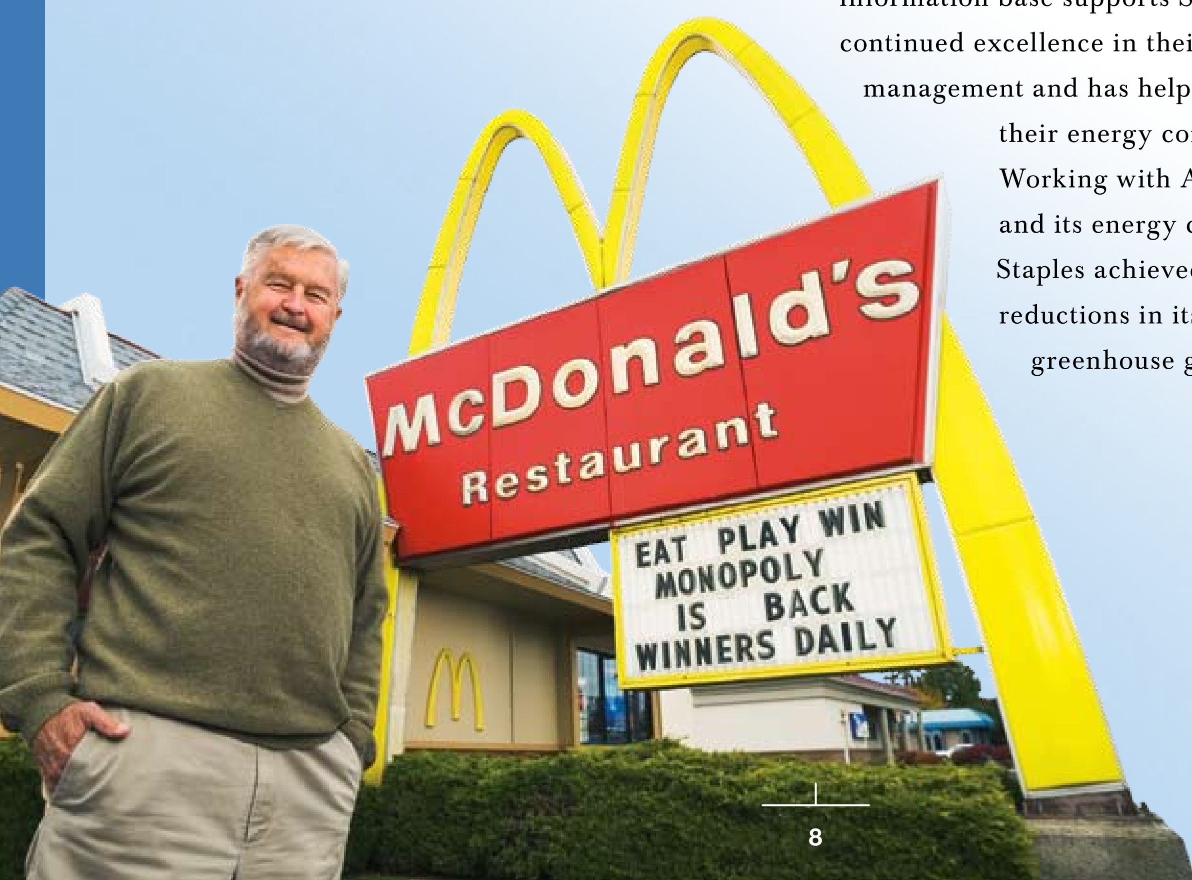
McDonald's

When Mark Ray started working at Spokane, Washington's first McDonald's in 1964, energy efficiency was the farthest thing from his mind. Now, some 44 years and 26 stores later, the cost of doing business is on the front burner for this franchise owner. "Our restaurants are energy intensive, with the grills, vats and HVAC units that we use," Ray said. "With increasing prices for food, packaging and wages, we need to save wherever we can." Avista worked with Ray's staff to put in place high tech Energy Management Systems (EMS). These monitor and adjust power and natural gas use, as well as notify managers electronically via text message or e-mail when equipment malfunctions – day or night. McDonald's first-year energy savings are estimated to be over 1.5 million kilowatt hours and nearly 23,000 therms – that cooks a lot of Big Macs.

Staples

Having access to data is the key to any successful energy management program. When office supply giant Staples, Inc. focused its attention on energy conservation, they turned to Advantage IQ, a subsidiary of Avista Corp., for help. Advantage IQ processes over 55,000 utility invoices per year for Staples' store locations throughout the U.S., creating a rich database of energy performance information.

Advantage IQ provides Staples with customized reports, highlighting energy performance indicators across the entire enterprise, as well as for individual stores. Staples uses the information to identify opportunities for change and to show employees how operational and behavioral shifts improve energy performance. This rich information base supports Staples' efforts for continued excellence in their overall energy management and has helped them improve their energy conservation efforts. Working with Advantage IQ and its energy consulting team, Staples achieved significant reductions in its overall U.S. greenhouse gas emissions.



CORPORATE **LEADERSHIP**

BOARD OF DIRECTORS

Erik J. Anderson, 50
President, Westriver Capital
Kirkland, Washington
Director since 2000

Kristianne Blake, 55
President, Kristianne Gates Blake, P.S.
Spokane, Washington
Director since 2000

Brian W. Dunham, 51
President & CEO, Northwest Pipe Co.
Vancouver, Washington
Director since 2008

Roy L. Eiguren, 57
President
Eiguren Public Law & Policy, PLLC
Boise, Idaho
Director since 2002

Jack W. Gustavel, 69
Chairman & CEO
Idaho Independent Bank
Coeur d'Alene, Idaho
Director since 2003

John F. Kelly, 64
President & CEO
John F. Kelly & Associates
Coral Gables, Florida
Director since 1997

Scott L. Morris, 51
Chairman of the Board,
President & CEO
Avista Corp.
Spokane, Washington
Director since 2007

Michael L. Noël, 67
President, Noël Consulting Company
Prescott, Arizona
Director since 2004

Heidi B. Stanley, 52
Chairman & CEO, Sterling Savings Bank
Spokane, Washington
Director since 2006

R. John Taylor, 59
Chairman & CEO
CropUSA Insurance Agency
Lewiston, Idaho
Director since 1985

BOARD COMMITTEES

Corporate Governance/ Nominating Committee
Kristianne Blake
Heidi B. Stanley
R. John Taylor
John F. Kelly – Chair

Executive Committee
Kristianne Blake
Jack W. Gustavel
R. John Taylor
Scott L. Morris – Chair

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

Compensation & Organization Committee
Michael L. Noël
John F. Kelly
R. John Taylor – Chair

Finance Committee
Brian W. Dunham
Jack W. Gustavel
Erik J. Anderson – Chair

Environmental, Safety & Security Committee
Erik J. Anderson
Jack W. Gustavel
Roy L. Eiguren – Chair

CORPORATE AND BUSINESS UNIT OFFICERS

Scott L. Morris, 51
Chairman of the Board,
President & CEO

Malyn K. Malquist, 56
Executive Vice President

Mark T. Thies, 45
Senior Vice President &
CFO

Marian M. Durkin, 55
Senior Vice President,
General Counsel &
Chief Compliance Officer

Karen S. Feltes, 53
Senior Vice President &
Corporate Secretary

Christy M. Burmeister-Smith, 52
Vice President, Controller &
Principal Accounting Officer

James M. Kensok, 50
Vice President & CIO

Don F. Kopczynski, 53
Vice President

David J. Meyer, 55
Vice President &
Chief Counsel for Regulatory
& Governmental Affairs

Kelly O. Norwood, 50
Vice President

Richard L. Storro, 58
Vice President

Dennis P. Vermillion, 47
Vice President &
Environmental Compliance Officer
President, Avista Utilities

Ann M. Wilson, 43
Vice President-Finance &
Treasurer

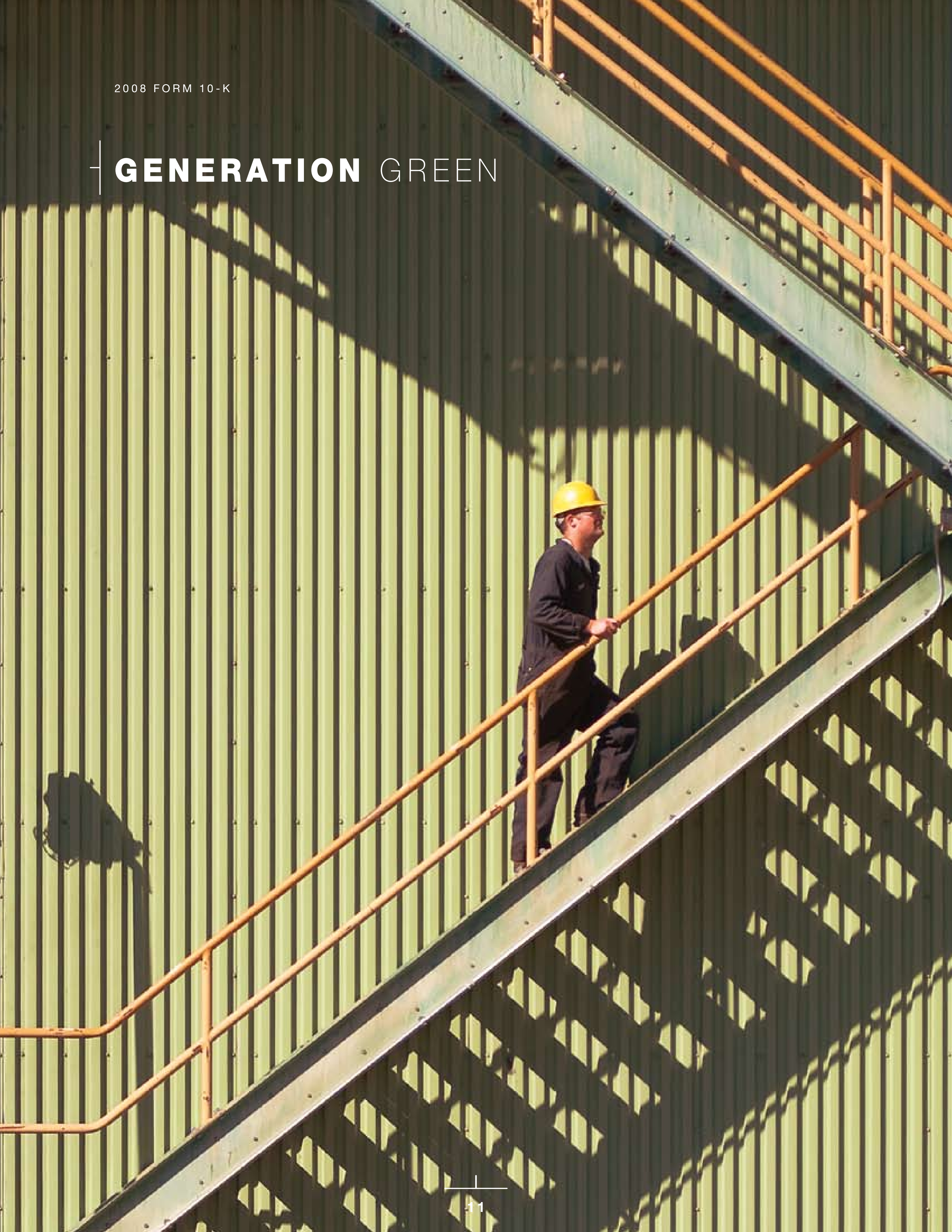
Roger D. Woodworth, 52
Vice President

Stuart A. Stiles, 48
President & CEO, Advantage IQ

FINANCIAL AND OPERATING HIGHLIGHTS

(Dollars in Thousands Except Statistics and Per Share Amounts or as Otherwise Indicated)	2008	2007	2006
FINANCIAL RESULTS			
Operating revenues	$ 1,676,763	$ 1,417,757	$ 1,506,311
Operating expenses	1,491,852	1,279,328	1,306,751
Income from operations	184,911	138,429	199,560
Net income	73,620	38,475	72,941
Earnings per common share, diluted	1.36	0.72	1.46
Earnings per common share, basic	1.37	0.73	1.48
Dividends paid per common share	0.690	0.595	0.570
Book value per common share	$ 18.30	$ 17.27	$ 17.41
Average common shares outstanding	53,637	52,796	49,162
Actual common shares outstanding	54,488	52,909	52,514
Return on average common equity	7.7%	4.2%	8.7%
Common stock closing price	$ 19.38	$ 21.54	$ 25.31
OPERATING RESULTS			
Avista Utilities			
Retail electric revenues	$ 635,102	$ 576,260	$ 554,136
Retail kWh sales (in millions)	9,017	8,912	8,775
Retail electric customers at year-end	354,657	351,512	345,450
Wholesale electric revenues	$ 141,744	$ 105,729	$ 126,208
Wholesale kWh sales (in millions)	1,964	1,594	2,117
Sales of fuel	$ 44,695	$ 12,910	$ 48,176
Other electric revenues	16,916	16,231	18,863
Retail natural gas revenues	440,692	424,246	416,010
Wholesale natural gas revenues	281,668	142,167	93,221
Transportation and other natural gas revenues	$ 11,847	$ 10,820	$ 11,324
Total therms delivered (in thousands)	845,710	700,433	629,906
Retail natural gas customers at year-end	314,102	310,535	304,586
Net income	$ 70,032	$ 43,822	$ 57,794
Advantage IQ			
Revenues	$ 59,085	$ 47,255	$ 39,636
Net income	6,090	6,651	6,255
Other			
Revenues	$ 45,014	$ 82,139	$ 198,737
Net income (loss)	(2,502)	(11,998)	8,892
FINANCIAL CONDITION			
Total assets	$ 3,630,747	$ 3,189,797	$ 4,056,508
Long-term debt (including current portion)	826,465	948,833	976,459
Long-term debt to affiliated trusts	113,403	113,403	113,403
Preferred stock (subject to mandatory redemption)	–	–	26,250
Stockholders' equity	$ 996,883	$ 913,966	$ 914,525

GENERATION GREEN



FORM 10-K

AVISTA CORP (AVA)

Filed: February 27, 2009 (Period: December 31, 2008)
Annual report which provides a comprehensive overview of the company for the past year.

POWERFUL GAINS WITH AVISTA. The financial report cover image, taken at the Kettle Falls generation plant, signifies the stability and strength investors can expect with Avista. When it comes to generating power with green technologies, it takes innovation to make it work as successfully as it does at Kettle Falls.

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

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED **DECEMBER 31, 2008** 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, together with Preferred Share Purchase Rights appurtenant thereto	New York Stock Exchange

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

Title of Class
Preferred Stock, Cumulative, Without Par Value

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

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

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

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

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

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]
(Do not check if a smaller reporting company)

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

The aggregate market value of the Registrant's outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $1,148,013,859 based on the last reported sale price thereof on the consolidated tape on June 30, 2008.

As of January 31, 2009, 54,629,586 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 May 7, 2009	Part III, Items 10, 11, 12, 13 and 14

INDEX

PART III

PART IV

SELECTED FINANCIAL DATA

* *not an applicable item in the 2008 calendar year for the Company*

ACRONYMS AND TERMS

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

Acronym/Term	Meaning
aMW	– Average Megawatt – a measure of the average rate at which a particular generating source produces energy over a period of time
AFUDC	– Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
AM&D	– Advanced Manufacturing and Development, does business as METALfx
APB	– Accounting Principles Board
Advantage IQ	– Advantage IQ, Inc., provider of facility information and cost management services for multi-site customers throughout North America, subsidiary of Avista Capital
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
Energy	– The amount of electricity produced or consumed over a period of time, measured in KWH or MWH
EITF	– Emerging Issues Task Force
ERM	– The Energy Recovery Mechanism in the state of Washington
FASB	– Financial Accounting Standards Board
FIN	– Financial Accounting Standards Board Interpretation
FERC	– Federal Energy Regulatory Commission

IPUC – Idaho Public Utilities Commission

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 Council

Noxon Rapids – The Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana

OASIS – Open Access Same-Time Information System

OPUC – The Public Utility Commission of Oregon

PCA – The Power Cost Adjustment mechanism in the state of Idaho

PLP – Potentially liable party

PUD – Public Utility District

PURPA – The Public Utility Regulatory Policies Act of 1978

RTO – Regional Transmission Organization

SFAS – Statement of Financial Accounting Standards

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

PART I

Our Annual Report on Form 10-K contains forward-looking statements, which should be read with the cautionary statements and important factors included at "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Forward-Looking Statements" on pages 24-25. 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 are subject to a variety of risks and uncertainties and other factors. Many of these factors are beyond our control and could have a significant effect on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in our statements.

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.

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, 2008, we employed 1,482 people in our utility operations and 645 people in our subsidiary businesses. Our corporate headquarters are in Spokane, Washington, the hub of the Inland Northwest. Agriculture, mining and lumber were the primary industries in the Inland Northwest for many years; today health care, education, finance, electronic and other manufacturing, tourism and the service sectors are growing in importance.

We have two reportable business segments as follows:

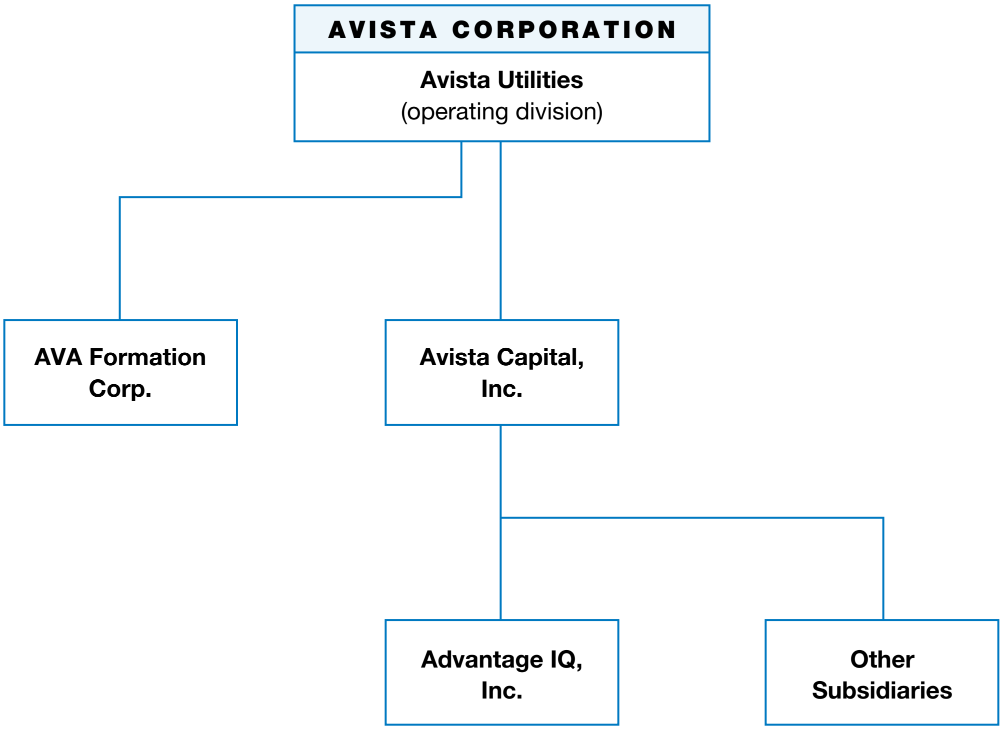
- **Avista Utilities** – an operating division of Avista Corp. comprising our regulated utility operations that started in 1889. Our utility generates, transmits and distributes electricity and distributes natural gas. The utility also engages in wholesale purchases and sales of electricity and natural gas.
- **Advantage IQ** – an indirect subsidiary of Avista Corp. that provides sustainable utility expense management solutions, partnering with multi-site companies across North America to assess and manage utility costs and usage. Primary product lines include processing, payment and auditing of energy, telecom, waste, water/sewer and lease bills as well as strategic management services.

In prior periods, we had a reportable Energy Marketing and Resource Management segment. The activities of this business segment were conducted primarily by Avista Energy, Inc. (Avista Energy), an indirect subsidiary of Avista Corp. On June 30, 2007, Avista Energy and Avista Energy Canada, Ltd. 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. Completion of this transaction effectively ended the majority of the operations of this segment. This business still owns natural gas storage facilities and has operating revenues and resource costs related to the power purchase agreement for a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant). The Lancaster Plant is owned by an unrelated third-party and all of the output from the plant is contracted to Avista Energy through 2026. The majority of the rights and obligations of the power purchase agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, we expect these rights and obligations will be transferred to Avista Utilities, subject to future regulatory approval. These remaining activities do not represent a reportable business segment in 2008 and are included in the Other category for segment reporting purposes. The historical activities were reclassified to the Other category in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 131, "Disclosures about Segments of an Enterprise and Related Information."

We have other businesses including sheet metal fabrication, venture fund investments and real estate investments. These activities do not represent a reportable business segment and are conducted by various indirect subsidiaries of Avista Corp., including Advanced Manufacturing and Development (AM&D), doing business as METALfx. Over time as opportunities arise, we plan to 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 the various other companies are subsidiaries of Avista Capital, Inc. (Avista Capital), which is wholly owned by Avista Corp. Our total common stockholders' equity was $996.9 million as of December 31, 2008, of which $77.5 million represented our investment in Avista Capital.

Our organization is illustrated below:



AVA Formation Corp. (AVA) is the company formed for purposes of completing the potential statutory share exchange and holding company implementation. AVA is currently a subsidiary of Avista Corporation. For further information, see "Note 28 of the Notes to Consolidated Financial Statements."

See "Item 6. Selected Financial Data" and "Note 30 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 2008, we supplied retail electric service to 355,000 customers and retail natural gas service to 314,000 customers across our entire service territory. See "Item 2. Properties" for further information with respect to our utility assets.

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, including surplus fuel in the wholesale market in connection with our resource optimization activities as described below.

We engage in an ongoing process of resource optimization. This involves the economic selection from available energy resources to serve load obligations and using 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 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 factors such as customer usage and weather as well as 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 energy to match expected resources to expected electric load requirements. Resource optimization involves our generating plant dispatch and scheduling available resources, and also includes transactions such as:

- purchasing fuel for generation,
- when economic, selling fuel and substituting wholesale purchases for the operation of our resources, and
- other wholesale transactions to capture the value of generation and transmission resources.

The 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. Our Open Access Same-Time Information System (OASIS) is part of the Joint Transmission Services Information Network that covers much of the United States. Transmission revenues were $9.5 million in 2008, $10.6 million in 2007 and $10.5 million in 2006.

Electric Requirements

Our peak electric native load requirement for 2008 occurred on December 16, 2008 at which time our total load was 2,383 MW consisting of:

- native load of 1,821 MW,
- long-term wholesale obligations of 270 MW, and
- short-term wholesale obligations of 292 MW.

At that time our maximum resource capacity available was 2,480 MW, which included:

- company-owned electric generation of 1,489 MW,
- long-term hydroelectric contracts with certain Public Utility Districts (PUDs) of 132 MW,
- other long-term wholesale contracts of 252 MW, and
- short-term wholesale purchases of 607 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 2008, our facilities had a total net capability of 1,768 MW, of which 56 percent was hydroelectric and 44 percent was thermal. See "Item 2. Properties" for detailed information with respect to 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 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 538 average megawatts (aMW) (or 4.7 million MWhs). Hydroelectric resources provided 535 aMW for 2008, 519 aMW for 2007 and 561 aMW for 2006.

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

	2008	2007	2006
Noxon Rapids	1,696	1,591	1,824
Cabinet Gorge	1,081	1,088	1,146
Post Falls	85	83	97
Upper Falls	78	63	69
Monroe Street	104	100	106
Nine Mile	105	100	110
Long Lake	497	471	553
Little Falls	205	193	223
Total company-owned hydroelectric generation	3,851	3,689	4,128
Long-term hydroelectric contracts with PUDs	833	861	787
Total hydroelectric generation	4,684	4,550	4,915

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 Corporation, 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. Natural gas may be used as an alternate fuel. 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. We did not operate these generating units significantly in 2008, 2007 and 2006. 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:

	2008	2007	2006
Coyote Springs 2	1,696	1,623	1,459
Colstrip	1,758	1,673	1,579
Kettle Falls GS	201	299	354
Northeast CT and Rathdrum CT	15	20	24
Boulder Park and Kettle Falls CT	23	25	18
Total thermal generation	3,693	3,640	3,434

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), we are required to purchase generation from qualifying facilities, including small hydroelectric and cogeneration projects, at rates approved by the Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC). These contracts expire at various times between 2015 and 2027. In February 2006, the PURPA was amended by the Federal Energy Regulatory Commission (FERC) as required by the Energy Policy Act of 2005 (Energy Policy Act). These amendments are not expected to have an effect on our PURPA-related contracts.

See "Avista Utilities Operating Statistics – Electric Operations – Electric Energy Resources" for annual quantities of purchased power, wholesale power sales and power from exchanges in 2008, 2007 and 2006.

Hydroelectric Relicensing

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). The Clark Fork Settlement Agreement that was entered into during 1999 and incorporated into the FERC license preserved the projects' economic peaking and load following operations. Also, 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 "Clark Fork Settlement Agreement" in "Note 26 of the Notes to Consolidated Financial Statements" for disclosure 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, and five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls, which have a total present capability of 144.1 MW) 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. Since the FERC was unable to issue new license orders prior to the August 1, 2007 (and subsequent August 1, 2008) expiration of the current license, an annual license was issued for all five plants, in effect extending the current license and its conditions until August 1, 2009. We have no reason to believe that Spokane River Project operations will be interrupted in any manner relative to the timing of the FERC's actions.

We filed a Notice of Intent to Relicense in July 2002. The formal consultation process involving planning and information gathering with stakeholder groups lasted through July 2005, when we filed our new license applications with the FERC. We initially requested the FERC to consider a license for Post Falls, which has a present capability of 18 MW, separately from the other four hydroelectric plants due to the complexity of issues related to the Post Falls development. In the license applications, we proposed a number of measures intended to address the impact of the Spokane River Project and enhance resources associated with the Spokane River. FERC licenses are granted for terms of 30 to 50 years.

Since our July 2005 filing of applications to relicense the Spokane River Project, the FERC has continued various stages of processing the applications. In May 2006, the FERC issued a notice requesting other parties to provide terms and conditions regarding the two license applications. In response to that notice, a number of parties including the Coeur d'Alene Tribe (the Tribe), the state of Idaho, Washington state agencies, and the United States Department of Interior (DOI) filed either recommended terms and conditions, pursuant to Sections 10(a) and 10(j) of the Federal Power Act (FPA), or mandatory conditions related to the Post Falls application, pursuant to Section 4(e) of the FPA. In January 2007, the FERC issued a draft Environmental Impact Statement (EIS). After review of comments, the FERC issued a final EIS in July 2007. This was the last administrative step for the FERC before the issuance of license orders; however, the FERC was unable to move forward prior to Federal Clean Water Act 401 Water Quality Certifications (Certifications) being issued by the states of Idaho and Washington.

The states of Idaho and Washington issued Certifications for the Project on June 5, 2008 and June 10, 2008, respectively. The Idaho Certification was based on a Settlement Agreement between Avista Corp., Idaho Department of Environmental Quality and the Idaho Department of Fish and Game, and is final. The Washington Certification, which was issued by the Washington Department of Ecology (Ecology), however, was appealed by Avista Corp., Inland Empire Paper and the Sierra Club/Center for Environmental Law and Policy. All issues, with the exception of one appealed by the Sierra Club/Center for Environmental Law and Policy (aesthetic spills at the Upper Falls plant) were resolved through a four-party Settlement Agreement. We are continuing negotiations on the remaining issue. A hearing is scheduled before the Washington Pollution Control Hearing Board in August 2009 to address the remaining issue under appeal.

On December 16, 2008 Avista, the United States DOI, and the Tribe reached agreement resolving FPA Section 4(e) conditions, as well as the payment of annual charges under Section 10(e) of the FPA regarding Post Falls, which stores water on a portion of the Coeur d'Alene Indian Reservation. The three parties submitted a request to the FERC on January 29, 2009 to incorporate the agreed-upon terms and conditions in a new single 50-year license for all five Spokane River hydroelectric plants.

The United States Department of Fish and Wildlife concurred, via a letter to FERC on July 31, 2008, that the Spokane River Project is not likely to adversely affect any listed or threatened endangered species.

We can not determine exactly when the FERC will complete action on the applications. Once granted, a new license will describe the final conditions we will be responsible to implement, and the term for a new license.

Our estimate of the potential cost of the conditions proposed for the Spokane River Project, based on estimates of what it would cost to implement the recommendations and conditions included in the FERC's final EIS and the numerous Settlement Agreements, total approximately $305 million over a 50-year period.

In addition, the December 16, 2008 settlement agreement between the Company and the Tribe resolved FPA Section 10(e), or storage payments related to the Post Falls hydroelectric facility. Under the agreement, we will pay the Coeur d'Alene Tribe $0.4 million annually for the first 20 years of a new FERC license and $0.7 million annually for the remainder of the license term for section 10(e) charges.

The WUTC approved, for future recovery, costs incurred in relicensing the Spokane River project, as well as the costs related to settlement with the Tribe. The WUTC approved deferred accounting treatment, with a carrying cost, until these costs are reflected in future retail rates. The IPUC approved similar deferred accounting treatment. Our general rate cases, filed in January 2009, reflect recovery of both the direct and deferred costs.

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.

The following is a forecast of our average annual energy requirements and resources for 2009, 2010, 2011 and 2012:

FORECASTED ELECTRIC ENERGY REQUIREMENTS AND RESOURCES (aMW)

	2009	2010	2011	2012
Requirements:				
System load	1,119	1,148	1,171	1,189
Contracts for power sales	140	139	139	139
Total requirements	1,259	1,287	1,310	1,328
Resources:				
Company-owned and contract hydro generation (1)	555	537	520	508
Company-owned base load thermal generation (2)	234	237	247	235
Company-owned other thermal generation (2)	294	291	281	292
Contracts for power purchases	367	604	521	487
Total resources	1,450	1,669	1,569	1,522
Surplus resources	191	382	259	194
Additional available energy (3)	153	153	153	153
Total surplus resources	344	535	412	347

(1) *The forecast assumes near normal hydroelectric generation (decline is related to changes in contracts with PUDs).*

(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 August 2007, we filed our 2007 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. Our preferred resource plan, which is part of the IRP, includes the addition of the following resources by 2017:

- 350 MW of natural gas generation,
- 300 MW of wind power,
- 87 MW of conservation,
- 38 MW of hydroelectric generation plant upgrades, and
- 35 MW of other renewable generation.

In response to new laws in the state of Washington regarding renewable resources and greenhouse gas emissions, the IRP excludes coal-based generation as a new resource. The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes.

We are required to file an IRP every two years. We will file an IRP in 2009 and the Preferred Resource Strategy may change based upon market, legislative and regulatory changes.

All of the output from the Lancaster Plant is contracted to Avista Energy through 2026 under a power purchase agreement. Avista Energy assigned the majority of its rights and obligations under this agreement to Shell Energy through the end of 2009. Beginning in 2010, we expect that these rights and obligations will be transferred to our utility operations, subject to approval by the WUTC and the IPUC.

In the second quarter of 2008, we completed the acquisition of a wind generation site. We expect to construct a 50 MW generation facility at an estimated cost of over $125 million with the majority of the costs expected to be incurred in 2013 and thereafter.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Issues and Other Contingencies" for information with respect 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, continue to 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 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.

As part of the process of balancing natural gas retail load requirements to resources obtained through wholesale purchases, we engage in wholesale 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. To the extent that our retail demand for natural gas is less than our available supply, or that we have under utilized interstate pipeline transportation capacity or excess storage capacity and there are price differentials that provide positive margins, we engage in wholesale sales of natural gas. These optimization activities increased significantly in 2008 as compared 2007. Wholesale sales are delivered through wholesale market facilities outside of our natural gas distribution system.

We make continuing projections of our natural gas loads and assess 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, 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 as much as four years into the future with the highest volumes hedged for the current and most immediately upcoming gas operating year (November through October). We also purchase a significant portion of our gas supply requirements in short-term and spot markets. Natural gas resource optimization activities include:

- wholesale market sales of surplus gas supplies,
- purchases and sales of natural gas to use underutilized pipeline capacity, and
- sales of excess natural gas 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 the natural gas transmission pipeline delivery points to the customers' premises. The total volume transported on behalf of our transportation customers for 2008, 2007 and 2006 was 148.7, 148.8 and 149.7 million therms. This represented 18 percent, 21 percent and 24 percent of total system deliveries.

Natural Gas Supply – We purchase all of our natural gas in the wholesale market. We are connected to multiple supply basins in the western United States and western Canada through firm capacity delivery rights on five 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 239.5 million therms.

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, 2010.

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 Energy controls 30.3 million therms of our capacity at Jackson Prairie and in conjunction with the asset sales agreement has assigned this capacity to Shell Energy through April 30, 2011. After that date, it is our intent to transfer this capacity to Avista Utilities for use in utility operations subject to regulatory approval.

Regulatory Issues

General – As a regulated public utility, we are subject to regulation by state utility commissions with respect to 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 service 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 of new rates is made on the basis of a "rate base" as of a date prior to the date of the request and allowable operating expenses for a 12-month test period ended prior to the date of the request. Although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag between the time we incur costs and the time when we can start recovering the costs through rates.

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 "Note 1 of Notes to Consolidated Financial Statements" for additional information about regulation, depreciation and deferred income taxes. See "Industry Developments" for additional information about deregulation, as well as changes with respect to transmission and wholesale electricity markets.

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 1 – Power Cost Deferrals and Recovery Mechanisms 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 or Natural Gas Trackers) – 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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Avista Utilities – Regulatory Matters – Purchased Gas Adjustments" and "Note 1 – Natural Gas Cost Deferrals and Recovery Mechanisms of the Notes to Consolidated Financial Statements" for detailed information on natural gas cost deferrals and recovery mechanisms in Washington, Idaho and Oregon.

Industry Developments

Energy Policy Act of 2005 – In August 2005, the Energy Policy Act was passed into law. The Energy Policy Act substantially affects the regulation of energy companies, including Avista Corp. Key provisions of the Energy Policy Act affecting us include, but are not limited to:

- reform of the hydroelectric licensing process,
- tax credits for incremental hydroelectric production placed into service before 2009,
- implementation of mandatory reliability standards, and
- authorization for the FERC to assess fines for non-compliance with FERC regulations and mandatory reliability standards.

The Energy Policy Act also has provisions related to the future operation and development of transmission systems and federal support for certain clean power initiatives and renewable energy technologies, including wind power generation. The Energy Policy Act repealed the Public Utility Holding Company Act of 1935 and, among other things:

- granted the FERC and state utility commissions access to the books and records of holding company systems,
- provides (upon request of a state commission or holding company system) for FERC review of allocations of costs of non-power goods and administrative services, and
- modifies the jurisdiction of the FERC over certain mergers and acquisitions involving public utilities or holding companies.

The implementation of the Energy Policy Act requires proceedings at the state level and the development of regulations by the FERC, the Department of Energy and other federal agencies.

Federal Initiatives Related to Wholesale Competition – Federal law promotes practices that open the electric wholesale energy market to competition. The FERC can require electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and to require 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 OASIS 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 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 – FERC Order No. 2000 (issued in 2000) required all utilities subject to FERC regulation to file a proposal to form a Regional Transmission Organization (RTO), or a description of efforts to participate in an RTO, and any existing obstacles to RTO participation. While it has not formally withdrawn Order No. 2000, the FERC has issued orders and made public policy statements indicating its support for the development and formation of regional independently-governed transmission organizations developed by such regions, but that do not necessarily meet all of the RTO functions and characteristics outlined in Order No. 2000. These include FERC Order No. 890 (issued in 2007), which required transmission providers 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 RTO in the region. ColumbiaGrid, a Washington nonprofit membership corporation, was formed to improve the operational efficiency, reliability, and planned expansion of the transmission grid in the Pacific Northwest. ColumbiaGrid members, including Avista Corp., elected an independent slate of directors to a three-member board in August 2006. ColumbiaGrid's responsibilities and related agreements with its members are currently being developed in a public process with broad participation. ColumbiaGrid's transmission planning and expansion functional agreement was accepted by the FERC and has been signed by a number of Pacific Northwest parties, including Avista Corp. We will continue to assess the benefits of entering into other functional agreements with ColumbiaGrid.

Reliability Standards – As a result of a significant blackout in northeastern and midwestern United States in 2003, the North American Electric Reliability Council (NERC), in conjunction with the FERC, conducted a comprehensive investigation of the outage and issued certain reliability-related recommendations. These recommendations addressed compliance with existing national and regional standards and initiatives to prevent or mitigate future blackouts. In February 2005, the NERC Board of Trustees approved voluntary reliability standards with the goal of restating existing standards in a manner that is clear, unambiguous, measurable and enforceable.

In February 2006, the FERC issued its final rule on the certification rules for a single Electric Reliability Organization (ERO). The NERC has been approved as the ERO and now has the authority to establish and enforce reliability standards, and has the ability to delegate authority to regional entities for the purpose of establishing and enforcing reliability standards.

As of January 2009, the FERC has approved 102 NERC Reliability Standards, including eight western region standards, making up the set of legally enforceable standards for the United States' bulk electric system. The first of these mandatory Reliability Standards became effective on June 18, 2007. We are required to self certify with regards to compliance with these mandatory standards. We are in compliance with these standards.

Global Climate Changes – Rising concerns about long-term global climate changes could have a significant effect on our business. We continue to monitor and evaluate the possible adoption of national, regional, or state requirements with respect to global climate changes. These requirements could result in significant costs for us to comply with restrictions on carbon dioxide and other emissions. Such requirements could also preclude us from developing certain types of generating plants or entering into new contracts for the output from generating plants that do not meet these requirements. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Issues and Other Contingencies" for further information.

Environmental Issues

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

In addition to the information provided in this section, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Issues and Other Contingencies" for further information.

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 accurately predict the economic costs to us resulting from future actions. 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 Relicensing" on page 5 for further information.

Air Quality – We must be in compliance with requirements under the Clean Air Act (CAA) and Clean Air Act Amendments (CAAA) in operating our thermal generating plants. We continue to monitor legislative developments at both the state and national level for potential further restrictions on sulfur dioxide, nitrogen oxide and carbon dioxide, as well as other greenhouse gas and mercury emissions. Compliance with new and proposed requirements and possible additional legislation or regulations will result in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities.

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 (SO2) under the CAAA. However, we do not expect Colstrip to be required to implement any additional SO2 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.

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 put in place 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 Company, along with the other owners of Colstrip, have completed the first phase of testing on two mercury control technologies. The joint owners of Colstrip were encouraged by preliminary results and believe that we will be able to comply with the Montana law without utilizing the temporary alternate emission limit provision. Preliminary estimates indicate that our share of installation capital costs will be $1.5 million and annual operating costs will increase by $2.9 million (beginning in late 2009). We will continue to seek recovery, through the ratemaking process, of the costs to comply with various air quality requirements.

Water Quality – See "Clark Fork Settlement Agreement" in "Note 26 of the Notes to Consolidated Financial Statements" regarding dissolved atmospheric gas levels that exceed state of Idaho and federal water quality standards downstream of Cabinet Gorge. See "Spokane River Relicensing" in "Note 26 of the Notes to Consolidated Financial Statements" for the Clean Water Act certifications for our relicensing of the Spokane River Project.

Other Environmental Issues – See "Colstrip Generating Project Complaint," and "Harbor Oil Inc. Site" in "Note 26 of the Notes to Consolidated Financial Statements" for information with respect to additional environmental issues.

Avista Corporation
Years Ended December 31

	2008	2007	2006
Electric Operations:			
Electric Operating Revenues (Dollars in Thousands):			
Residential	$ 279,641	$ 251,357	$ 234,714
Commercial	247,714	224,179	221,193
Industrial	101,785	95,207	92,961
Public street and highway lighting	5,962	5,517	5,268
Total retail revenues	635,102	576,260	554,136
Wholesale revenues	141,744	105,729	126,208
Revenues from sales of fuel	44,695	12,910	48,176
Other revenues	16,916	16,231	18,863
Total electric operating revenues	$ 838,457	$ 711,130	$ 747,383
Electric Energy Sales (Thousands of MWhs):			
Residential	3,744	3,670	3,578
Commercial	3,188	3,132	3,110
Industrial	2,059	2,084	2,062
Public street and highway lighting	26	26	25
Total retail energy sales	9,017	8,912	8,775
Wholesale energy sales	1,964	1,594	2,117
Total electric energy sales	10,981	10,506	10,892
Electric Energy Resources (Thousands of MWhs):			
Hydro generation (from Company facilities)	3,851	3,689	4,128
Thermal generation (from Company facilities)	3,693	3,640	3,434
Purchased power – hydro generation from long-term contracts with PUDs	833	861	787
Purchased power – wholesale	3,253	2,959	3,101
Power exchanges	(17)	(18)	35
Total power resources	11,613	11,131	11,485
Energy losses and Company use	(632)	(625)	(593)
Total energy resources (net of losses)	10,981	10,506	10,892
Number of Electric Retail Customers (Average for Period):			
Residential	311,381	306,737	300,940
Commercial	39,075	38,488	37,912
Industrial	1,388	1,378	1,388
Public street and highway lighting	434	426	425
Total electric retail customers	352,278	347,029	340,665
Electric Residential Service Averages:			
Annual use per customer (KWh)	12,023	11,965	11,888
Revenue per KWh (in cents)	7.47	6.85	6.56
Annual revenue per customer	$ 898.07	$ 819.45	$ 779.94
Electric Average Hourly Load (aMW)	1,102	1,089	1,069

Avista Corporation

Years Ended December 31

	2008	2007	2006
Electric Operations (continued):			
Resource Availability at Time of System Peak (MW):			
Total requirements (winter)			
Retail native load	1,821	1,685	1,656
Wholesale obligations	562	367	431
Total requirements (winter)	2,383	2,052	2,087
Total resource availability (winter)	2,480	2,302	2,618
Total requirements (summer)			
Retail native load	1,602	1,631	1,643
Wholesale obligations	431	381	588
Total requirements (summer)	2,033	2,012	2,231
Total resource availability (summer)	2,250	2,434	2,551
Cooling Degree Days: (1)			
Spokane, WA			
Actual	478	576	615
30-year average	394	394	394
% of average	121%	146%	156%

(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

	2008	2007	2006
Natural Gas Operations:			
Natural Gas Operating Revenues (Dollars in Thousands):			
Residential	$ 276,386	$ 264,546	$ 257,753
Commercial	152,147	148,416	146,581
Industrial and interruptible	12,159	11,284	11,676
Total retail natural gas revenues	440,692	424,246	416,010
Wholesale revenues	281,668	142,167	93,221
Transportation revenues	6,327	6,638	6,499
Other revenues	5,520	4,182	4,825
Total natural gas operating revenues	$ 734,207	$ 577,233	$ 520,555
Therms Delivered (Thousands of Therms):			
Residential	210,125	195,756	192,833
Commercial	128,224	121,557	120,989
Industrial and interruptible	12,196	10,833	11,040
Total retail	350,545	328,146	324,862
Wholesale	345,916	223,084	154,884
Transportation	148,723	148,765	149,717
Interdepartmental and Company use	526	438	443
Total therms delivered	845,710	700,433	629,906
Sources of Natural Gas Supply (Thousands of Therms):			
Purchases	710,137	561,277	483,038
Storage – injections	(76,491)	(35,228)	(17,892)
Storage – withdrawals	66,271	28,842	18,181
Natural gas for transportation	148,723	148,765	149,717
Distribution system losses	(2,930)	(3,223)	(3,138)
Total natural gas supply	845,710	700,433	629,906
Number of Natural Gas Retail Customers (Average for Period):			
Residential	277,892	273,415	267,345
Commercial	32,901	32,327	31,746
Industrial and interruptible	297	302	295
Total natural gas retail customers	311,090	306,044	299,386
Natural Gas Residential Service Averages:			
Annual use per customer (therms)	756	716	721
Revenue per therm (in dollars)	$ 1.32	$ 1.35	$ 1.34
Annual revenue per customer	$ 994.58	$ 967.56	$ 964.12
Heating Degree Days: [1]			
Spokane, WA			
Actual	7,052	6,539	6,332
30-year average	6,820	6,820	6,820
% of average	103%	96%	93%
Medford, OR			
Actual	4,569	4,386	4,167
30-year average	4,533	4,533	4,533
% of average	101%	97%	92%

(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 solutions to multi-site companies across North America to assess and manage utility costs and usage. Our 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 this process, Advantage IQ analyzes and audits invoices, then presents consolidated bills on-line, as well as processing payments for these expenses. 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 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:

	2008	2007	2006
Customers at year-end	537	403	373
Billed sites at year-end	417,078	199,088	199,752
Dollars of customer bills processed (in billions)	$ 16.7	$ 12.5	$ 10.8

The 2008 amounts include customers and sites of Cadence Network, which was acquired by Advantage IQ in July 2008 (see "Note 5 of the Notes to Consolidated Financial Statements").

OTHER BUSINESSES

In prior periods, we had a reportable Energy Marketing and Resource Management segment. This segment primarily included the results of Avista Energy. On June 30, 2007, Avista Energy and its subsidiary, Avista Energy Canada, completed the sale of substantially all of their contracts and ongoing operations to Shell Energy, as well as to certain other subsidiaries of Shell Energy. Completion of this transaction effectively ended the majority of the operations of this business segment. Avista Energy Canada provided natural gas services to industrial and commercial customers in British Columbia, Canada.

The historical activities of Avista Energy included trading electricity and natural gas, the optimization of generation assets owned by other entities, long-term electric supply contracts, natural gas storage and electric transmission and natural gas transportation arrangements.

This business still owns natural gas storage facilities and has operating revenues and resource costs related to the power purchase agreement for the Lancaster Plant. These remaining activities do not represent a reportable business segment in 2008 and are included in the Other category for segment reporting purposes. We expect these assets to eventually be transferred to our utility operations, subject to regulatory approval.

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

- real estate investments (primarily commercial office buildings),
- investments in venture capital funds and low income housing, and
- the remaining investment in a previous fuel cell subsidiary of the Company.

Over time as opportunities arise, we plan to 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 “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – 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.

Our results of operations, financial condition and cash flows are significantly affected by weather.

Weather has a significant effect on our utility operations related to variations in temperatures and precipitation. Weather impacts include customer demand and operating revenues and the cost of energy we supply. 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.

Precipitation (consisting of snowpack and its melting pattern plus rainfall) and other streamflow conditions (such as regional water storage operations) significantly impact hydroelectric generation capability. Variations in hydroelectric generation inversely affect our reliance on market purchases and thermal generation. There is a significantly higher cost for resources other than hydroelectric generation, and these costs can be greater than the retail revenue from the related energy delivered to customers.

Regional precipitation and snowpack conditions typically have a significant effect on the wholesale price of electricity. Plentiful hydroelectric generation typically depresses market prices, sometimes when we are selling surplus energy, while constrained hydroelectric generation typically elevates market prices, sometimes when we are purchasing energy. In general, high demand for electricity will generally increase both the quantity needed and price of fuel for generation and wholesale market prices. These price patterns typically fluctuate seasonally with regional supply and demand and they are exaggerated or moderated by the relative level of supply, fuel costs, and end user energy demand.

As a result of these factors operating in combination, our net cost of power supply – the difference between our generating and market purchases costs and revenue from wholesale sales – varies significantly because of weather.

Financial market conditions may impact our results and our liquidity.

The deterioration in the financial markets and credit availability that arose in 2008 and the current state of 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. Additionally, we may experience an increase in uncollectible customer accounts and collection times. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenues and future growth. Concerns about the regional or local economy may also influence the willingness of regulators to grant necessary rate increases to recover our costs.

The deterioration in the financial markets has also resulted in significant declines in the market values of assets held by our pension plan (which impacts the funded status of the plan) and will increase future funding obligations and pension expense.

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

We need to maintain access to adequate levels of credit with financial institutions for short-term liquidity. We have a $320 million committed line of credit, which is scheduled to expire in April 2011, and a $200 million committed line of credit, which is scheduled to expire in November 2009. We cannot predict whether we will have access to credit beyond the expiration dates. 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.

We are dependent on our ability to access long-term capital markets.

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.

We are subject to commodity price risk.

Our utility operations are affected by electric and natural gas commodity price risk. 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.

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.

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

- amount of North American production and production capacity that can be delivered to our service areas,
- level of imports and exports, particularly from Canada by pipeline and to a growing extent by LNG,
- inventory levels 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.

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 regularly review the need for retail electric and natural gas rate changes in each state in which we provide service. We expect to periodically file for rate increases with regulatory agencies to recover our costs and provide a reasonable return to our 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, and it may take several years for us to recover deferred costs.

We defer income statement recognition and current recovery from customers of certain power and natural gas costs that are higher than what is currently authorized by regulators. These excess 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 for the potential of disallowance by state regulators.

Despite the opportunity to eventually recover a substantial portion of power and natural gas costs, our operating cash flows are negatively affected until these costs are recovered from customers.

Relicensing our hydroelectric facilities located on the Spokane River at a cost-effective level with reasonable terms and conditions may not be possible.

We have six hydroelectric plants on the Spokane River, and five of these are under one FERC license. Collectively, these five plants are referred to as the Spokane River Project. Since the FERC was unable to issue new license orders prior to the August 1, 2007 (and subsequent August 1, 2008) expiration of the current license, an annual license was issued for all five plants, in effect extending the current license and its conditions until August 1, 2009.

The relicensing process for the Spokane River Project is a public regulatory process that involves complex natural resource, recreation and cultural issues. We cannot predict the terms and conditions that will ultimately be imposed by the FERC. The costs of these terms and conditions could have a negative effect on our operating expenses and require significant utility capital expenditures reducing net income and cash flows. We also cannot predict whether the FERC will ultimately issue new licenses or whether we will be willing to meet the licensing requirements to continue to operate the Spokane River Project. We plan to request regulatory approval to recover future licensing costs. However, we cannot be certain that these costs will be recovered through the rate making process.

We are subject to 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.

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.

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. 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 the collateral.

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 unhedged positions, 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.

Risk management procedures may not prevent losses.

We have a risk management policy and control procedures designed to mitigate energy market risks. However, our risk management policy and control procedures cannot prevent material losses in all possible situations or from all potential causes. As a result, there can be no assurance that our risk management procedures will prevent losses that could negatively affect our operating revenues, resource costs, derivative assets and liabilities, and operating cash flows.

Downgrades in our credit ratings could limit our ability to obtain financing, adversely affect the terms of financing and impact our ability to acquire energy resources.

In late 2007 and early 2008, we restored an overall corporate investment grade credit rating with the two major credit rating agencies. Our credit ratings were downgraded during the fourth quarter of 2001, which resulted in an overall corporate credit rating that was below investment grade. The downgrades were due to liquidity concerns primarily related to the significant amount of purchased power and natural gas costs that we incurred in our utility operations. These downgrades increased our debt service costs. Any future downgrades could limit our ability to access capital markets or obtain other financing on reasonable terms. In addition, future downgrades could require us to provide letters of credit and/or collateral to lenders and counterparties.

An increase in interest rates could negatively affect our future results of operations and cash flows.

We expect utility capital expenditures to be over $210 million in each of 2009 and 2010. In addition to ongoing needs for our utility distribution system, significant projects include the continued enhancement of our transmission system and upgrades to generating facilities. Our forecasts indicate that we will issue new securities to fund a portion of these requirements. Rising interest rates could increase future debt service costs and decrease operating cash flows to the extent we issue new securities to fund these obligations.

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 quality and availability,
- disruptions to our information systems and other administrative resources required for normal operations,
- weather conditions and natural disasters that can cause physical damage to property, requiring repairs to restore utility service, and
- terrorism and other malicious threats.

We are currently the subject of several regulatory proceedings, and we are named in multiple lawsuits related to our participation in western energy markets as disclosed in "Note 26 of the Notes to Consolidated Financial Statements."

Through our utility operations and the prior operations of Avista Energy, we are involved in a number of legal and regulatory proceedings and complaints with respect 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 other 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 26 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 which may adversely effect 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 published by government agencies, such as the FERC, NERC and the EPA. Future legislation or administrative rules could have a material adverse effect on our operations, results of operations, financial condition and cash flows.

We may be affected by long-term global climate changes.

Rising concerns about long-term global climate changes could have a significant effect on our business. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of hydroelectric generation capacity. Changing temperatures could also increase or decrease customer demand. We continue to monitor legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide, carbon dioxide, as well as other greenhouse gas and mercury emissions. Our operations could 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.

Environmental laws and regulations may have the effect of:

- increasing the costs of generating plants,
- increasing the lead time for the construction of new generating plants,
- requiring modification of our existing generating plants,
- requiring existing generating plants to be curtailed or shut down,
- increasing the risk of delay on construction projects,
- reducing the amount of energy available from our generating plants, and
- restricting the types of generating plants that can be built.

As such, compliance with such environmental laws and regulations could result in increases to capital expenditures and operating expenses.

We have contingent liabilities, as disclosed in "Note 26 of the Notes to Consolidated Financial Statements," and cannot predict the outcome of these matters.

We have multiple 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 rate making process. See "Note 26 of the Notes to Consolidated Financial Statements" for further details of these matters.

Other Environmental Matters

We are subject to environmental regulation by federal, state and local authorities related to our past, present and future operations. Environmental issues include, but are not limited to, contamination of certain parcels of land and waters that:

- we currently own,
- we have formerly owned or have used as a customer,
- are adjacent to our property,
- are located on the Spokane or Clark Fork Rivers, or
- are downstream of our hydroelectric facilities.

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 various mortgage indentures.

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	83.3
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	548.4
Total Hydroelectric		913.6	981.7
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	56.3
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	786.5
Total Generation Properties		1,744.8	1,768.2

(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, 2008.*

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

Electric Distribution and Transmission Plant

We operate approximately 18,100 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of approximately 660 miles of 230 kV line and 1,500 miles of 115 kV line. We also own an 11 percent interest (representing 465 MW of capacity) in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution system also includes 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 to the major load centers in our service area, as well as to transfer power between points of interconnection with adjoining electric transmission systems. These lines interconnect at various locations with the BPA, Grant County PUD, PacifiCorp, NorthWestern Energy and Idaho Power Company. These interconnections serve as points of delivery for power from generating facilities outside of our distribution territory, 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 the Kettle Falls GS. These lines interconnect with the BPA, Chelan County PUD, the Grand Coulee Project Hydroelectric Authority, Grant County PUD, NorthWestern Energy, PacifiCorp, Pend Oreille County PUD and Puget Sound Energy. Both the 115 kV and 230 kV interconnections with the BPA are used to exchange 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, 1,900 miles in Idaho and 2,300 miles in Oregon. The natural gas distribution 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 239.5 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 Energy controls 30.3 million therms of our capacity at Jackson Prairie and in conjunction with the asset sales agreement has assigned this capacity to Shell Energy through April 30, 2011. After that date, it is our intent to transfer this capacity to Avista Utilities for use in utility operations subject to regulatory approval.

ITEM 3. LEGAL PROCEEDINGS

See "Note 26 of Notes to Consolidated Financial Statements" for information with respect to legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

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, 2009, there were 12,312 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 (Avista Utilities).

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 13, 2009, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.18 per share on the Company's common stock.

As further discussed at "Note 28 of the Notes to the Consolidated Financial Statements," the IPUC accepted a stipulation that we entered with the IPUC Staff that sets forth a variety of conditions if and when we implement a holding company structure. One of the conditions would require IPUC approval of any dividend to the holding company that would reduce utility common equity below 25 percent. We entered into a similar agreement in Washington. This agreement would require WUTC approval of any dividend to the holding company that would reduce utility common equity below 30 percent. The utility equity component was approximately 47.6 percent as of December 31, 2008.

For additional information, refer to "Notes 1, 23, 24 and 25 of Notes to Consolidated Financial Statements." For high and low stock prices, as well as dividend information, refer to "Note 31 of Notes to Consolidated Financial Statements."

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

	2008	2007	2006	2005	2004
Operating Revenues:					
Avista Utilities	$ 1,572,664	$ 1,288,363	$ 1,267,938	$ 1,161,317	$ 972,574
Advantage IQ	59,085	47,255	39,636	31,748	23,444
Other	45,014	82,139	198,737	185,971	292,773
Intersegment Eliminations	–	–	–	(19,429)	(137,211)
Total	$ 1,676,763	$ 1,417,757	$ 1,506,311	$ 1,359,607	$ 1,151,580
Income (Loss) from Operations (pre-tax):					
Avista Utilities	$ 174,245	$ 150,053	$ 177,049	$ 165,101	$ 134,073
Advantage IQ	11,297	11,012	10,479	6,973	1,742
Other	(631)	(22,636)	12,032	(20,327)	4,655
Total	$ 184,911	$ 138,429	$ 199,560	$ 151,747	$ 140,470
Net Income (Loss):					
Avista Utilities	$ 70,032	$ 43,822	$ 57,794	$ 52,299	$ 32,467
Advantage IQ	6,090	6,651	6,255	3,922	577
Other	(2,502)	(11,998)	8,892	(11,233)	2,570
Net income before cumulative effect of accounting change	73,620	38,475	72,941	44,988	35,614
Cumulative effect of accounting change	–	–	–	–	(460)
Net income	$ 73,620	$ 38,475	$ 72,941	$ 44,988	$ 35,154
Average common shares outstanding, basic	53,637	52,796	49,162	48,523	48,400
Average common shares outstanding, diluted	54,028	53,263	49,897	48,979	48,886
Common shares outstanding at year-end	54,488	52,909	52,514	48,593	48,472
Earnings per Common Share, Diluted:					
Earnings before cumulative effect of accounting change	$ 1.36	$ 0.72	$ 1.46	$ 0.92	$ 0.73
Cumulative effect of accounting change	–	–	–	–	(0.01)
Total earnings per common share, diluted	$ 1.36	$ 0.72	$ 1.46	$ 0.92	$ 0.72
Total earnings per common share, basic	$ 1.37	$ 0.73	$ 1.48	$ 0.93	$ 0.73
Dividends paid per common share	$ 0.690	$ 0.595	$ 0.57	$ 0.545	$ 0.515
Book value per common share at year-end	$ 18.30	$ 17.27	$ 17.41	$ 15.82	$ 15.50
Total Assets at Year-End:					
Avista Utilities	$ 3,434,844	$ 3,009,499	$ 2,895,883	$ 2,838,154	$ 2,608,155
Advantage IQ	125,911	108,929	100,431	46,094	47,318
Other	69,992	71,369	1,060,194	2,064,246	1,056,148
Total	$ 3,630,747	$ 3,189,797	$ 4,056,508	$ 4,948,494	$ 3,711,621
Long-Term Debt (including current portion)	$ 826,465	$ 948,833	$ 976,459	$ 1,029,514	$ 986,988
Long-Term Debt to Affiliated Trusts	113,403	113,403	113,403	113,403	113,403
Preferred Stock Subject to Mandatory Redemption	–	–	26,250	28,000	29,750
Stockholders' Equity	$ 996,883	$ 913,966	$ 914,525	$ 768,849	$ 751,106
Ratio of Earnings to Fixed Charges [1]	2.41	1.67	2.14	1.73	1.58

(1) See Exhibit 12 for computations.

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

FORWARD-LOOKING STATEMENTS

From time to time, we make forward-looking statements such as statements regarding projected or future:

- financial performance,
- 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. Most of these factors are beyond our control and many of them 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 and its effect on energy demand and generation, including the effect of precipitation and temperatures on the availability of hydroelectric resources and the effect of temperatures on customer demand and wholesale energy markets;
- global financial and economic conditions (including the availability of credit) and their effect on the Company's ability to obtain funding for working capital and long-term capital requirements on acceptable terms;
- economic conditions in the Company's service areas, including the effect on the demand for, and customers' ability to pay for, the Company's utility services;
- 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;
- changes in actuarial assumptions, the interest rate environment and the actual return on plan assets for our pension plan, which can affect future funding obligations, costs and pension plan liabilities;
- changes in wholesale energy prices that can 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;
- 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;
- the effect of state and federal regulatory decisions affecting our ability to recover costs and/or earn a reasonable return including, but not limited to, the disallowance of costs that we have deferred, and the influence local economic conditions may have on the willingness of regulators to grant necessary rate increases;
- 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;
- the outcome of pending regulatory and legal proceedings arising out of the "western energy crisis" of 2000 and 2001, and including possible retroactive price caps and resulting 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, electric retail wheeling and transmission costs;
- the ability to relicense and maintain licenses for our hydroelectric generating facilities at cost-effective levels with reasonable terms and conditions;
- unplanned outages at any of our generating facilities or the inability of facilities to operate as intended;
- unanticipated delays or changes in construction costs, as well as our ability to obtain required operating permits for present or prospective facilities;
- natural disasters that can disrupt energy production or delivery, as well as the availability and costs of materials and supplies and support services;
- blackouts or disruptions of interconnected transmission systems;
- the potential for terrorist attacks or other malicious acts, particularly with respect to our utility assets;
- 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;
- the loss of significant customers and/or suppliers;
- 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;
- increasing health care costs and the resulting effect on health insurance provided to our employees and retirees;
- increasing costs of insurance, changes in coverage terms and our ability to obtain insurance;
- employee issues, including changes in collective bargaining unit agreements, strikes, work stoppages or the loss of key executives, as well as 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, data contained in our records and other data 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 of such factors, nor can we assess the effect of each such factor on our business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

The following discussion and analysis is provided for the consolidated financial condition and results of operations of Avista Corporation (Avista Corp. or the Company) and its subsidiaries. This discussion focuses on significant factors concerning our financial condition and results of operations and should be read along with the consolidated financial statements.

POTENTIAL HOLDING COMPANY FORMATION

At the Annual Meeting of Shareholders in May 2006, the shareholders of Avista Corp. approved a proposal to proceed with a statutory share exchange, which would change the Company's organization to a holding company structure. We received approval from the FERC in April 2006 (conditioned on approval by the state regulatory agencies), the IPUC in June 2006 and the WUTC in February 2007. We also filed for approval from the utility regulators in Oregon and Montana and proceedings are pending in each of these jurisdictions. The statutory share exchange is subject to the receipt of the remaining regulatory approvals and the satisfaction of other conditions. We can not predict when the remaining regulatory approvals will be obtained or if they will be on terms acceptable to us. See further information at "Note 28 of the Notes to Consolidated Financial Statements."

BUSINESS SEGMENTS

We have two reportable business segments as follows:

- **Avista Utilities** – an operating division of Avista Corp. comprising 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. that provides sustainable utility expense management solutions, partnering with multi-site companies across North America to assess and manage utility costs and usage. Primary product lines include processing, payment and auditing of energy, telecom, waste, water/sewer and lease bills as well as strategic management services.

In prior periods, the Company had a reportable Energy Marketing and Resource Management segment. The activities of this business segment were conducted primarily by 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, as well as to certain other subsidiaries of Shell Energy. Completion of this transaction effectively ended the majority of the operations of this segment. The remaining activities do not represent a reportable business segment in 2008 and are included in the Other category for segment reporting purposes. The historical activities were reclassified to the Other category in accordance with the provisions of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." See "Note 3 of the Notes to Consolidated Financial Statements" for further information.

We have other businesses including sheet metal fabrication, venture fund investments and real estate investments. These activities are conducted by various indirect subsidiaries of Avista Corp., including Advanced Manufacturing and Development (AM&D), doing business as METALfx. The Other category is not a reportable segment.

Avista Energy, Advantage IQ and the various other companies are subsidiaries of Avista Capital, Inc. (Avista Capital) which is a direct, wholly owned subsidiary of Avista Corp. Our total common stockholders' equity was $996.9 million as of December 31, 2008, of which $77.5 million represented our investment in Avista Capital.

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

	2008	2007	2006
Avista Utilities	$ 70,032	$ 43,822	$ 57,794
Advantage IQ	6,090	6,651	6,255
Other	(2,502)	(11,998)	8,892
Net income	$ 73,620	$ 38,475	$ 72,941

EXECUTIVE LEVEL SUMMARY

Overall

Our operating results and cash flows are primarily from:

- regulated utility operations (Avista Utilities), and
- facility information and cost management services for multi-site customers (Advantage IQ).

Our net income was $73.6 million for 2008, an increase from $38.5 million for 2007. This increase was primarily due to increased earnings at Avista Utilities (primarily due to the implementation of general rate increases in Washington and Idaho) and the $11.9 million net loss at Avista Energy (included in Other) in 2007.

Effective July 2, 2008, Advantage IQ acquired Cadence Network, a 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, which is subject to redemption. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to redeem their shares of Advantage IQ stock 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. Based on the estimated fair market value of Advantage IQ common stock held by the previous owners of Cadence Network, the liability was $28.8 million as of December 31, 2008 related to this potential redemption obligation.

We would like to monetize at least a portion of our investment in Advantage IQ within the next four years. The potential monetization of Advantage IQ depends on future market conditions, growth of the business and other factors. There can be no assurance that we will be able to complete a monetization event.

In late 2007 and early 2008, Moody's Investors Service and Standard & Poor's upgraded our credit ratings, which resulted in an investment grade rating for our senior unsecured debt and corporate rating from each of these rating agencies. The upgrades reflected several steps taken over the past few years to lower our business risk profile and improve financial metrics.

It is important to note that we are at the lower end of the investment grade category. We are working to continuously strengthen our credit ratings by improving earnings and operating cash flows, controlling costs and reducing the debt ratios.

Our operations are affected by global financial and economic conditions. The instability within the financial markets has caused industry wide concern regarding the ability to access sufficient capital at a reasonable cost. The turmoil has also resulted in significant declines in the market values of assets held by pension plans (which may impact the funded status of pension plans) as well as concerns regarding credit risk.

We are observing modest declines in employment throughout our service area due to cutbacks in the construction, forest products, mining and manufacturing sectors. However, agriculture, health care, higher education and governmental sectors continue to perform well. Non-farm employment contraction for 2008 as compared to 2007 was 2.3 percent in Spokane, 2.1 percent in Medford and 4.1 percent in Coeur d'Alene, compared to the national average of 2.1 percent. Unemployment rates are much higher than a year ago, having moved above the national average in our eastern Washington, northern Idaho and southern Oregon service areas. Unemployment rates for December 2008 were 7.6 percent in Spokane, 7.3 percent in Coeur d'Alene and 9.9 percent in Medford, compared to the national average of 7.2 percent. The housing market has remained relatively balanced with stable prices keeping foreclosures in check. Foreclosure rates for Spokane, Coeur d'Alene and Medford were all less than 0.4 percent for 2008 compared to the national average of 1.85 percent.

Avista Utilities

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

- weather conditions,
- 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
- regulatory decisions, allowing our utility to recover costs, including purchased power and fuel costs, on a timely basis, and to earn a fair return on investment.

Our utility net income was $70.0 million for 2008, an increase from $43.8 million for 2007 partially due to an increase in gross margin (operating revenues less resource costs). The increase in gross margin was primarily due to the implementation of the general rate increases in Washington and Idaho effective January 1, 2008 and October 1, 2008, respectively. The increase in net income was also partially due to a decrease in interest expense. This was partially offset by an increase in other operating expenses. Also contributing to the increase in net income for 2008 was $5.7 million (pre-tax) of interest income, partially offset by $1.4 million (pre-tax) of interest expense, related to income tax settlements reached during the third quarter of 2008 and the resulting refunds received and payments made to the Internal Revenue Service. Additionally, the improvement in 2008 results as compared to 2007 was also due to a regulatory disallowance recorded in the third quarter of 2007.

We plan to continue to invest in generation, transmission and distribution systems with a focus on providing reliable service to our customers. Utility capital expenditures were $219.2 million for 2008. We expect utility capital expenditures to be over $210 million for 2009.

Advantage IQ

Advantage IQ had net income of $6.1 million for 2008, a decrease from $6.7 million for 2007. This was primarily due to the decrease in our ownership percentage in the business in connection with the acquisition of Cadence Network effective July 2, 2008, an increase in amortization of intangible assets (related to the Cadence acquisition) and lower short-term interest rates (which decreases interest revenue). During 2009, we are anticipating slower internal growth at Advantage IQ than had been expected as some of their clients are experiencing bankruptcies and store closures in these difficult economic times. Additionally, interest revenue is expected to be lower in 2009 due to the historic low short-term interest rate environment that we are currently experiencing and that is expected to continue throughout 2009.

Other Businesses

Over time as opportunities arise, we plan to 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. The net loss for these operations was $2.5 million for 2008 compared to a net loss of $12.0 million for 2007. Contributing to the net loss in 2008 was losses on long-term venture fund investments and litigation costs. The net loss for 2007 was primarily due to Avista Energy.

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. Current conditions in the financial markets have resulted in companies having limited access to capital on reasonable terms and have resulted in a significant increase in borrowing rates for corporations. 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.

We have a committed line of credit in the total amount of $320.0 million with an expiration date of April 5, 2011. We had $250.0 million of cash borrowings and $24.3 million in letters of credit outstanding as of December 31, 2008, under our $320.0 million committed line of credit.

In November 2008, we entered into a new committed line of credit in the total amount of $200.0 million with an expiration date of November 24, 2009. We had no borrowings outstanding as of December 31, 2008, under our $200.0 million committed line of credit.

We entered into the $200.0 million line of credit to ensure we had adequate liquidity, as conditions in the financial markets resulted in limited access to capital on reasonable terms.

In March 2008, we amended our accounts receivable sales facility with Bank of America, N.A. to extend the termination date to March 2009. We expect to renew this facility before the March 2009 expiration. Under this facility, we can sell without recourse, on a revolving basis, up to $85.0 million of accounts receivable. Based upon calculations under this agreement, we had the ability to sell up to $85.0 million as of December 31, 2008. We had sold $17.0 million of accounts receivable under this facility as of December 31, 2008.

As of December 31, 2008, we had a combined $313.7 million of available liquidity under our $320.0 million committed line of credit, $200.0 million committed line of credit, and $85.0 million revolving accounts receivable sales facility.

In 2008 debt maturities were $404 million, the majority being the $273 million of 9.75 percent Unsecured Senior Notes that matured on June 1, 2008. In April 2008, we issued $250 million of 5.95 percent First Mortgage Bonds to fund a significant portion of this debt that matured. In December 2008, we issued $30 million of 7.25 percent First Mortgage Bonds due in 2013 and refinanced $17 million of Pollution Control Bonds. The proceeds from the $30 million issuance, together with funds borrowed under the $320 million committed line of credit, were used to fund $25 million of medium term notes that matured in December 2008 and to purchase $66.7 million of Pollution Control Bonds in December 2008 that we will hold until they are refunded at a later date.

We anticipate issuing long-term debt and common stock during 2009 to reduce the balances outstanding under our committed line of credit agreements. Additionally, we are planning to remarket or refund the $66.7 million of Pollution Control Bonds during 2009. We do not have any scheduled long-term debt maturities in 2009. The current portion of long-term debt includes $17 million of Pollution Control Bonds because they are subject to purchase at any time at the option of the bond holder due to the interest rate currently being reset daily. After considering the issuances of long-term debt and common stock during 2009, we expect net cash flows from operating activities and our committed line of credit agreements (total of $520.0 million) to provide adequate resources to fund:

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

In December 2006, we entered into a sales agency agreement with a sales agent to issue up to 2 million shares of our common stock from time to time. We issued 750,000 shares of common stock (total net proceeds of $16.6 million) under this sales agency agreement during the third quarter of 2008. These were our first issuances under the sales agency agreement. We plan to continue to evaluate issuing common stock in future periods.

Due to market conditions and the decline in the fair value of pension plan assets, our contributions to the pension plan in 2009 are expected to be $48 million as compared to the $28 million we contributed in 2008. The final determination of pension plan contributions beyond 2009 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 projected benefit obligation). We have adequate liquidity to meet our pension plan funding obligations for 2009.

AVISTA UTILITIES – ELECTRIC RESOURCES

As of December 31, 2008, our generation facilities had a total net capability of 1,768 MW, of which 56 percent was hydroelectric and 44 percent was thermal. In addition to company owned generation resources, we have a number of long-term power purchase and exchange contracts that increase our available resources. See "Note 7 of the Notes to Consolidated Financial Statements" for information with respect to the resource optimization process.

SETTLEMENT WITH THE COEUR D'ALENE TRIBE

In December 2008, we reached a comprehensive agreement with the Coeur d'Alene Tribe (Tribe) and the United States Department of Interior over our past and future use of Tribal land and water in the operation of our Spokane River Hydroelectric Projects, including the Post Falls dam. Pursuant to the settlement, we will compensate the Tribe a total of $39 million for past storage of water for the period from 1907 through 2007. We paid $25 million in December 2008 with remaining payments of $10 million in 2009 and $4 million in 2010. This obligation has been recorded as a regulatory asset as of December 31, 2008. We will compensate the Tribe for future storage of water through payments of $0.4 million per year beginning in 2008 and continuing through the first 20 years of a new license and $0.7 million per year through the remaining term of the license.

In addition to past and future storage payments, the agreement provides for annual payments to fund a variety of protection, mitigation and enhancement measures on the Coeur d'Alene Reservation that would be implemented over the life of a new FERC license. This will be accomplished through the creation of a Coeur d'Alene resource protection trust fund. Annual payments from Avista Corp. to the trust fund for protection, mitigation and enhancement measurements would commence with the issuance of the new FERC license and are expected to total approximately $100 million over an assumed 50-year license term.

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
- more closely align earned returns with 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 in-service dates of major infrastructure investments and the timing of changes in major revenue and expense items. Primarily due to the significant amount of capital investments we are making in our utility infrastructure and increasing operating costs, we filed general rate cases in Washington and Idaho in January 2009. We are planning to file in Oregon during the first half of 2009.

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	January 2009	8.22%	10.2%	46%
Idaho electric and natural gas	October 2008	8.45%	10.2%	48%
Oregon natural gas	April 2008	8.21%	10.0%	50%

As approved by the WUTC, on January 1, 2008, electric rates for our Washington customers increased by an average of 9.4 percent, which was designed to increase annual revenues by $30.2 million. As part of this general rate increase, the base level of power supply costs used in the Energy Recovery Mechanism (ERM) calculations was updated. Also, on January 1, 2008, natural gas rates increased by an average of 1.7 percent, which was designed to increase annual revenues by $3.3 million.

In September 2008, we entered into a settlement stipulation with respect to our general rate case that was filed with the WUTC in March 2008. Other parties to the settlement stipulation are the staff of the WUTC, Northwest Industrial Gas Users, and the Energy Project. The Industrial Customers of Northwest Utilities (ICNU) joined in portions of the settlement and the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) did not join in the settlement stipulation. 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 is 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 is designed to increase annual revenues by $4.8 million.

Our original request in March 2008 was for base electric rate increases averaging 10.3 percent, which was designed to increase annual revenues by $36.6 million. Our original request was to increase base natural gas rates by an average of 3.3 percent, which was designed to increase annual revenues by $6.6 million.

The settlement was based on an overall rate of return of 8.22 percent with a common equity ratio of 46.3 percent and a 10.2 percent return on equity. Our original request was based on a proposed overall rate of return of 8.43 percent with a common equity ratio of 46.3 percent and a 10.8 percent return on equity.

On January 27, 2009, Public Counsel filed a Petition for Judicial Review of the WUTC's December 2008 order approving our multiparty settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These include whether settlement costs associated with resolving the dispute with the Coeur d'Alene Tribe were prudent and whether recovery of such costs would constitute illegal "retroactive ratemaking." Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony by us to update our filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses.

The appeal itself does not prevent the new rates from going into effect. The appeals process may take several months and a decision is not expected until later in 2009. The court will either affirm the decision of the WUTC in its entirety or reverse the decision, in whole or in part, and remand the matter back to the

WUTC for further consideration, which could possibly result in refunds.

In January 2009, we filed a general rate case with the WUTC requesting to increase base electric rates for our Washington customers. In the general rate case filing, we requested a net electric rate increase of 8.6 percent. The net electric rate increase is based on a requested 16.0 percent increase in billed rates with an offsetting 7.4 percent reduction in the current Energy Recovery Mechanism (ERM) surcharge. We also requested a 2.4 percent increase in natural gas rates. The filing is designed to increase annual base electric service revenues by $69.8 million ($37.5 million net after considering the reduction in the current ERM surcharge) and increase annual natural gas service revenues by $4.9 million. Our request is based on a proposed rate of return on rate base of 8.68 percent, with a common equity ratio of 47.5 percent and an 11.0 percent return on equity. The WUTC generally has up to 11 months to review a general rate case filing.

As part of the general rate case settlement agreement that was modified and approved by the WUTC in December 2005, we agreed to increase the utility equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008. Our utility equity component met this target as it was approximately 47.6 percent as of December 31, 2008.

In August 2008, we entered into an all-party settlement stipulation with respect to our 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 our Idaho customers increased by an average of 12.0 percent, which is 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 is designed to increase annual revenues by $3.9 million.

Our original request was for base electric rate increases averaging 16.7 percent, which was designed to increase annual revenues by $32.3 million. We also requested to increase base natural gas rates by an average of 5.8 percent, which was designed to increase annual revenues by $4.7 million.

In January 2009, we filed a general rate case with the IPUC requesting to increase base electric rates for our Idaho customers. In the general rate case filing, we requested a net electric rate increase of 7.8 percent. The net electric rate increase is based on a requested 12.8 percent increase in billed rates with an offsetting 5.0 percent reduction in the current Power Cost Adjustment (PCA) surcharge. We also requested a 3.0 percent increase in natural gas rates. The filing is designed to increase annual base electric service revenues by $31.2 million ($18.9 million net after considering the reduction in the current PCA surcharge) and increase annual natural gas service revenues by $2.7 million. Our request is based on a proposed rate of return on rate base of 8.8 percent, with a common equity ratio of 50 percent and an 11.0 percent return on equity. The IPUC generally has up to seven months to review a general rate case filing.

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).

Purchased Gas Adjustments

Effective January 6, 2009, natural gas rates decreased 4.7 percent in Idaho. Effective January 16, 2009, natural gas rates decreased 3.0 percent in Washington. Effective November 1, 2008, natural gas rates decreased 4.1 percent in Oregon. Purchased gas adjustments (PGAs) are designed to pass through changes in natural gas costs to our customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, we absorb 10 percent of the difference between actual and projected gas costs for unhedged supply. In October 2008, the OPUC issued an order based upon an extensive review of the current PGA mechanism. The order reaffirmed the current mechanism and included several minor modifications that we believe will not have a significant impact on our gas purchasing and hedging strategies or net income. Total net deferred natural gas costs were a liability of $18.6 million as of December 31, 2008, a change from a net asset of $2.4 million as of December 31, 2007.

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 and applies only to taxes paid and collected on or after January 1, 2006.

In February 2008, we reached a settlement with respect to the refund liability for the 2006 tax report that was approved by the OPUC in April 2008. The approved settlement provided for a refund to customers of $1.5 million, including interest. In October 2008, we filed the tax report for 2007 showing taxes paid to be less than taxes collected by $2.0 million before interest. We claimed that no refund should be made in connection with the 2007 tax report, asserting that such a refund would violate the "fair and reasonable" standard provided for under OPUC rules. In January 2009, we reached a settlement that would result in no refund related to the 2007 tax report. A joint brief related to the settlement was filed in February 2009. The OPUC is expected to rule on the settlement before April 15, 2009. We have recorded a potential refund liability related to the 2008 tax report of $1.4 million. However, any final determination of refunds or surcharges to customers will ultimately be determined based on final calculations for the 2008 tax year.

Natural Gas Decoupling

In January 2007, the WUTC approved the implementation of a natural gas decoupling mechanism. Because our rate structure provides for recovery of the majority of fixed costs on a per-therm (sales volume) basis, energy efficiency and conservation objectives have been directly at odds with the recovery of fixed costs, which do not vary with the volume of natural gas sold. Decoupling separates the direct link between natural gas sales volume and the recovery of the fixed cost of providing service to our customers. Our decoupling mechanism should allow us to recover lost margin resulting from lower usage by Washington customers due to conservation and price elasticity. However, the mechanism does not provide rate adjustments related to abnormal weather. The decoupling mechanism is a two and one half year "pilot" that began in January 2007. Continuation of the mechanism beyond June 2009 is subject to review and approval by the WUTC. A rate adjustment in any one year would be limited to no more than 2 percent. Our most recent decoupling rate adjustment became effective November 1, 2008. The rate adjustment is designed to recover $0.7 million from Washington residential and small commercial customers over a twelve month period. This represents an incremental rate increase of 0.3 percent, reflecting 90 percent of the lost margin due to conservation by the Company's Washington residential and small commercial gas customers during the period July 2007 through June 2008.

Wind Generation Costs

In June 2008, we filed a petition with the WUTC and the IPUC requesting that costs (including land, turbine down payments and other preliminary costs) associated with wind generation projects be accounted for as construction work in progress, allowing for the accrual of an allowance for funds used during construction (AFUDC). In July 2008, the IPUC approved our request. In December 2008, we withdrew our request in Washington and plan to address this item in a future proceeding.

Power Cost Deferrals and Recovery Mechanisms

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 our Washington customers.

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.

The initial amount of power supply costs in excess of or below the level in retail rates, which we either incur the cost of, or receive the benefit from, 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. Through December 31, 2008, 50 percent of the annual power supply cost variance in this range was deferred for future surcharge or rebate to customers and we incurred the cost of, or received the benefit from, the remaining 50 percent. 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 incur the cost of, or receive the benefit from, 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 through December 31, 2008:

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%
+/- excess over $10 million	90%	10%

Based upon the approved September 2008 settlement stipulation with respect to our general rate case that was filed with the WUTC in March 2008 (the settlement stipulation was approved in December 2008), the ERM was adjusted for the sharing level for the annual power supply cost variance in the $4.0 million to $10.0 million band. The adjustment resulted in 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. The 50 percent customers/50 percent Company sharing was maintained when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. The revisions to the ERM became effective on January 1, 2009.

The following is a summary of the revised 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 1st 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. In August, 2008, the WUTC issued an order, which approved the recovery of power costs incurred for 2007. Additionally, we must make a filing (no sooner than January 1, 2011), to allow all interested parties the opportunity to review the ERM, and make recommendations to the WUTC related to the continuation, modification or elimination of the ERM.

We have a Power Cost Adjustment (PCA) mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The October 1 rate adjustments recover or rebate power costs deferred during the preceding July – June twelve-month period. The PCA rate surcharge, as approved by the IPUC, is 0.61 cents per KWh (designed to recover $21.7 million) for the period October 1, 2008 through September 30, 2009.

The following table shows activity in deferred power costs for Washington and Idaho during 2007 and 2008 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2006	$ 70,159	$ 9,357	$ 79,516
Activity from January 1 – December 31, 2007:			
Power costs deferred	16,344	16,750	33,094
Interest and other net additions	3,023	788	3,811
Recovery of deferred power costs through retail rates	(31,002)	(5,732)	(36,734)
Deferred power costs as of December 31, 2007	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

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.

2008 compared to 2007

Utility revenues increased $284.3 million to $1,572.7 million as a result of increases in natural gas revenues of $157.0 million and electric revenues of $127.3 million. The increase in natural gas revenues was primarily the result of increased wholesale revenues (due to increased prices and volumes) of $139.5 million and retail natural gas revenues (due to increased volumes) of $16.4 million. The increase in electric revenues was primarily due to increased retail revenues (primarily due to the Washington general rate increase implemented on January 1, 2008 and the Idaho general rate increase implemented on October 1, 2008) of $58.8 million, wholesale revenues of $36.0 million and sales of fuel of $31.8 million.

Non-utility energy marketing and trading revenues decreased $36.3 million to $25.2 million. This category of revenues decreased significantly with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007. The remaining revenues primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. We expect that these rights and obligations will be transferred to our regulated utility, subject to future approval by the WUTC and the IPUC.

Other non-utility revenues increased $11.0 million to $78.9 million as a result of an increase in revenues from Advantage IQ of $11.8 million primarily due to customer growth and the acquisition of Cadence Network in the third quarter of 2008, partially offset by a decrease in interest earnings on funds held for customers (due to lower interest rates).

Utility resource costs increased $251.0 million due to increases in natural gas resource costs of $147.9 million and electric resource costs of $103.1 million. The increase in natural gas resource costs primarily reflects an increase in the volume and price of natural gas purchases and increased amortization of deferred natural gas costs. The increase in electric resource costs reflects an increase in base resource costs as set forth in the Washington general rate case implemented on January 1, 2008 and the Idaho general rate case implemented on October 1, 2008, as well as higher purchased power and fuel costs.

Utility other operating expenses increased $7.8 million primarily due to an increase of $4.0 million in electric generation operating and maintenance expenses, as well as a $3.4 million increase in electric distribution expenses. This was partially offset by the impairment of a turbine in the third quarter of 2007 of $2.3 million.

Utility depreciation and amortization increased $1.8 million primarily due to additions to utility plant.

Non-utility resource costs decreased $45.1 million. This category of expenses decreased significantly with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007. The remaining costs primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. We expect that these rights and obligations will be transferred to our regulated utility, subject to future approval by the WUTC and the IPUC.

The net change in other non-utility operating expenses was a decrease of $2.7 million due to:

- a decrease of $13.2 million in the other businesses due to the sale of Avista Energy's ongoing operations, partially offset by
- an increase of $10.5 million for Advantage IQ due to expanding operations and the acquisition of Cadence Network in the third quarter of 2008.

Interest expense decreased $5.7 million due to the redemption of all outstanding preferred stock in September 2007 and the effect of long-term debt maturities during 2007 and 2008, which were primarily funded with proceeds from the sale and liquidation of Avista Energy's assets and the issuance of long-term debt at lower interest rates. This was partially offset by interest expense of $1.4 million related to an income tax settlement.

Interest expense to affiliated trusts decreased $1.2 million due to a decrease in the variable interest rate.

Other income-net decreased $1.5 million primarily due to a decrease in interest income of $4.6 million. The decrease in interest income was primarily due to the disposition of Avista Energy's ongoing operations. Also contributing to the decrease were losses on long-term venture fund investments. The net decrease was offset by $5.7 million of interest income recorded on the IRS settlement agreement for the 2001 through 2003 tax years and the resulting refund. See "Note 13 of the Notes to Consolidated Financial Statements" for additional information with respect to the IRS settlement agreement.

Income taxes increased $21.3 million primarily due to increased income before income taxes. Our effective tax rate was 38.3 percent for 2008 compared to 38.7 percent for 2007.

2007 compared to 2006

Utility revenues increased $20.4 million to $1,288.4 million as a result of an increase in natural gas revenues of $56.7 million, which were the result of increased wholesale (primarily due to increased volumes) and retail (due to an increase in rates and volumes) natural gas sales. This was partially offset by a decrease in electric revenues of $36.3 million reflecting decreased wholesale revenues and sales of fuel, partially offset by increased retail revenues.

Non-utility energy marketing and trading revenues decreased $116.0 million to $61.5 million. This category of revenues decreased significantly in 2007 with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007.

Other non-utility revenues increased $7.0 million to $67.9 million as a result of an increase in revenues from Advantage IQ of $7.6 million primarily due to customer growth, as well as an increase in interest earnings on funds held for customers. This was partially offset by decreased other revenues of $0.6 million due in part to decreased sales at AM&D.

Utility resource costs increased $29.4 million due to an increase in natural gas resource costs of $54.1 million primarily reflecting an increase in the volume of natural gas purchases. The increase in natural gas resource costs was partially offset by a decrease in electric resource costs of $24.7 million primarily due to a decrease in other fuel costs (economic sales of fuel that was not used in generation) and a decrease in the net amortization of deferred power costs. The decrease in other fuel costs was consistent with reduced resource optimization activities during 2007 and lower sales of fuel and wholesale sales as part of the process of balancing loads and resources. The decrease in the net amortization of deferred power costs reflected higher electric resource costs as compared to the amount included in base electric rates and the resulting increase in deferrals for future recovery from customers. In 2007, we deferred $33.1 million of power costs as compared to $5.7 million in 2006.

Utility other operating expenses increased $11.3 million primarily due to the impairment of a turbine of $2.3 million, increased maintenance expenses of $3.5 million, natural gas distribution expenses of $1.8 million, outside services of $2.3 million, and regulatory commission fees of $2.7 million.

Utility depreciation and amortization increased $4.2 million primarily due to additions to utility plant.

Utility taxes other than income taxes increased $2.6 million primarily due to increased retail electric and natural gas revenues and related taxes.

Non-utility resource costs decreased $75.5 million. This category of expenses decreased significantly in 2007 with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007.

The net change in other non-utility operating expenses was an increase of $1.2 million due to:

- an increase of $6.8 million for Advantage IQ due to expanding operations and consulting services, and
- a decrease of $5.6 million in the other businesses due the sale of Avista Energy's ongoing operations, to lower operating expenses at AM&D and the accrual of an environmental liability at Avista Development during 2006, partially offset by the loss on the sale of Avista Energy's operations.

Interest expense decreased $9.9 million due to our issuance of fixed rate long-term debt that replaced maturing debt (which had relatively high interest rates) in the fourth quarter of 2006 and a decrease in interest expense on short-term borrowings under our committed line of credit. The decrease in short-term borrowings partially reflects the availability of funds from the Avista Energy transaction.

Capitalized interest increased $0.9 million due to increased utility construction activity and the associated increase in construction work in progress balances.

In the Washington general rate case settlement, we agreed to write off $3.8 million of unamortized debt repurchase costs effective September 30, 2007. These costs were for premiums paid to repurchase higher coupon debt prior to its scheduled maturity as part of an effort to reduce interest expense.

Other income-net increased $2.2 million due to an increase in equity-related AFUDC (consistent with increased utility construction activity) and gains on long-term venture fund investments, partially offset by a decrease in interest income and interest on power and natural gas deferrals.

Income taxes decreased $17.7 million primarily due to decreased income before income taxes. Our effective tax rate was 38.7 percent for 2007 compared to 36.5 percent for 2006. The increase in the effective tax rate was primarily due to certain tax adjustments in 2007 and 2006. In 2007, the Company recognized tax adjustment expenses of $1.0 million. In 2006, the Company recognized adjustments related to IRS audits and adjustments for the 2005 filed federal tax return. In total, these adjustments had a favorable impact to recorded 2006 tax expense of $1.3 million.

AVISTA UTILITIES

2008 compared to 2007

Net income for the utility was $70.0 million for 2008 compared to $43.8 million for 2007. Utility income from operations was $174.2 million for 2008 compared to $150.1 million for 2007. 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 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		Total	
	2008	2007	2008	2007	2008	2007
Operating revenues	$ 838,457	$ 711,130	$ 734,207	$ 577,233	$ 1,572,664	$ 1,288,363
Resource costs	425,373	322,237	606,616	458,761	1,031,989	780,998
Gross margin	$ 413,084	$ 388,893	$ 127,591	$ 118,472	$ 540,675	$ 507,365

Utility operating revenues increased $284.3 million and utility resource costs increased $251.0 million, which resulted in an increase of $33.3 million in gross margin. The gross margin on electric sales increased $24.2 million and the gross margin on natural gas sales increased $9.1 million. The increase in our electric and natural gas gross margin was primarily due to the implementation of general rate increases in Washington effective January 1, 2008 and Idaho effective October 1, 2008. The increase was also partially due to colder weather in 2008, which increased customer usage during the heating season and customer growth. The Company absorbed $7.4 million in 2008 and $8.5 million in 2007 under the ERM.

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	
	2008	2007	2008	2007
Residential	$ 279,641	$ 251,357	3,744	3,670
Commercial	247,714	224,179	3,188	3,132
Industrial	101,785	95,207	2,059	2,084
Public street and highway lighting	5,962	5,517	26	26
Total retail	635,102	576,260	9,017	8,912
Wholesale	141,744	105,729	1,964	1,594
Sales of fuel	44,695	12,910	–	–
Other	16,916	16,231	–	–
Total	$ 838,457	$ 711,130	10,981	10,506

Retail electric revenues increased $58.8 million due to an increase in:

- total MWhs sold (increased revenues $7.3 million) primarily due to customer growth and an increase in use per customer (primarily due to colder weather), and
- revenue per MWh (increased revenues $51.5 million) primarily due to the Washington general rate increase implemented on January 1, 2008 and the Idaho general rate increase implemented on October 1, 2008.

Wholesale electric revenues increased $36.0 million due to an increase in sales prices (increased revenues $9.3 million), and an increase in sales volumes (increased revenues $26.7 million).

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 $31.8 million due to increased thermal generation resource optimization activities.

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	
	2008	2007	2008	2007
Residential	$ 276,386	$ 264,546	210,125	195,756
Commercial	152,147	148,416	128,224	121,557
Interruptible	5,428	5,040	5,758	5,003
Industrial	6,731	6,244	6,438	5,830
Total retail	440,692	424,246	350,545	328,146
Wholesale	281,668	142,167	345,916	223,084
Transportation	6,327	6,638	148,723	148,765
Other	5,520	4,182	526	438
Total	$ 734,207	$ 577,233	845,710	700,433

The $16.4 million increase in retail natural gas revenues was due to an increase in volumes (increased revenues $28.1 million), partially offset by lower retail rates (decreased revenues $11.7 million). We sold more retail natural gas in 2008 primarily due to colder weather during the heating season and customer growth. The decrease in retail rates reflects the purchased gas adjustments implemented in the fourth quarter of 2007, partially offset by the Washington general rate increase implemented on January 1, 2008 and Idaho general rate increase implemented on October 1, 2008.

The increase in our wholesale revenues of $139.5 million was due to an increase in prices (increased revenues $39.5 million) and an increase in volumes (increased revenues $100.0 million). Wholesale sales reflect the balancing of loads and resources and the sale of resources in excess of load requirements as part of the natural gas procurement process. Additionally, we engage in optimization of under utilized interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. This activity increased significantly in 2008 as compared to 2007. Variances between the revenues and costs of the sale of resources in excess of load requirements 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	
	2008	2007	2008	2007
Residential	311,381	306,737	277,892	273,415
Commercial	39,075	38,488	32,901	32,327
Interruptible	–	–	40	41
Industrial	1,388	1,378	257	261
Public street and highway lighting	434	426	–	–
Total retail customers	352,278	347,029	311,090	306,044

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

	2008	2007
Electric resource costs:		
Power purchased	$ 193,924	$ 158,245
Power cost amortizations, net of deferrals	25,464	3,641
Fuel for generation	134,446	125,043
Other fuel costs	43,103	16,454
Other regulatory amortizations, net	10,490	4,437
Other electric resource costs	17,946	14,417
Total electric resource costs	425,373	322,237
Natural gas resource costs:		
Natural gas purchased	579,248	433,140
Natural gas amortizations, net of deferrals	20,372	16,875
Other regulatory amortizations, net	6,996	8,746
Total natural gas resource costs	606,616	458,761
Total resource costs	$1,031,989	$ 780,998

Power purchased increased $35.7 million due in part to an increase in wholesale prices (increased costs $23.0 million). The increase was also due to an increase in the volume of power purchases (increased costs $12.7 million) primarily due to an increase in sales volumes (due to colder weather, customer growth, and optimization).

Net amortization of deferred power costs was $25.5 million for 2008 compared to $3.6 million for 2007. During 2008, we recovered (collected as revenue) $30.9 million of previously deferred power costs in Washington and $11.7 million in Idaho. During 2008, we deferred $7.0 million of power costs in Washington and $10.0 million of power costs in Idaho, as power supply costs exceeded the amount included in base retail rates.

Fuel for generation increased $9.4 million due to an increase in thermal generation volumes and an increase in fuel prices.

Other fuel costs increased $26.6 million. This represents fuel that was purchased for generation, but was later sold when conditions indicated that it was not economic to use the fuel in generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel. Other fuel costs were less than the revenues we received from selling the natural gas. We account for this difference under the ERM in Washington and the PCA in Idaho. The increase in other fuel costs was primarily due to increased thermal generation resource optimization activities and increased fuel prices.

Other regulatory amortizations increased $6.1 million primarily due to amortization of demand side management program expenses.

The expense for natural gas purchased increased $146.1 million due to an increase in total therms purchased and the price of natural gas. The increase in total therms purchased was due to an increase in wholesale sales as part of the balancing of loads and resources as part of the natural gas procurement process and an increase in retail sales volumes. We engage in optimization of under utilized interstate pipeline transportation and storage capacity through wholesale purchases and sales of natural gas. This activity increased significantly in 2008 as compared to 2007. During 2008, we amortized $20.4 million of deferred natural gas costs compared to $16.9 million for 2007.

2007 compared to 2006

Net income for the utility was $43.8 million for 2007 compared to $57.8 million for 2006. Utility income from operations was $150.1 million for 2007 compared to $177.0 million for 2006. This decrease in income from operations was primarily due to decreased gross margin (operating revenues less resource costs). The decrease was also due to an increase in:

- other utility operating expenses (primarily due to the impairment of a turbine, increased maintenance expenses, natural gas distribution expenses, outside services, and regulatory commission fees).
- depreciation and amortization (due to additions to utility plant), and
- taxes other than income taxes (primarily due to increased retail electric and natural gas revenues and related 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	
	2007	2006	2007	2006	2007	2006
Operating revenues	$ 711,130	$ 747,383	$ 577,233	$ 520,555	$ 1,288,363	$ 1,267,938
Resource costs	322,237	346,980	458,761	404,666	780,998	751,646
Gross margin	$ 388,893	$ 400,403	$ 118,472	$ 115,889	$ 507,365	$ 516,292

Utility operating revenues increased $20.4 million and utility resource costs increased $29.4 million, which resulted in a decrease of $8.9 million in gross margin. The gross margin on electric sales decreased $11.5 million and the gross margin on natural gas sales increased $2.6 million. The decrease in our electric gross margin was primarily due to the difference in electric resource costs as compared to the amount included in base retail rates resulting in the expense of $8.5 million of power supply costs in Washington under the ERM during 2007. We received a benefit of $2.6 million under the ERM in 2006. The increase in power supply costs for 2007 (as compared to the amount included in base rates) was primarily due to lower hydroelectric generation, higher purchased power and fuel costs and greater use of our thermal generating resources (particularly Coyote Springs 2). The increase in natural gas gross margin was primarily due to colder weather in the first quarter of 2007 and customer growth.

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	
	2007	**2006**	**2007**	**2006**
Residential	$ 251,357	$ 234,714	3,670	3,578
Commercial	224,179	221,193	3,132	3,110
Industrial	95,207	92,961	2,084	2,062
Public street and highway lighting	5,517	5,268	26	25
Total retail	576,260	554,136	8,912	8,775
Wholesale	105,729	126,208	1,594	2,117
Sales of fuel	12,910	48,176	–	–
Other	16,231	18,863	–	–
Total	$ 711,130	$ 747,383	10,506	10,892

Retail electric revenues increased $22.1 million due to an increase in:

- total MWhs sold (increased revenues $8.8 million) primarily due to customer growth and partially due to an increase in use per customer, and
- revenue per MWh (increased revenues $13.3 million) primarily due to the elimination of the BPA residential exchange credit.

The increase in use per customer was primarily due to colder weather in the first and fourth quarters.

Wholesale electric revenues decreased $20.5 million due to:

- a decrease in sales volumes (decreased revenues $34.7 million) consistent with decreased volume of wholesale purchases and decreased resource optimization activities, partially offset by
- an increase in sales prices (increased revenues $14.2 million).

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 decreased $35.3 million as a greater percentage of our fuel purchases were used in generation.

Other electric revenues decreased $2.6 million primarily due to revenues of $3.0 million from the sale of claims we had against Enron Corporation (Enron) and certain of its affiliates received in 2006 (first quarter).

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	
	2007	**2006**	**2007**	**2006**
Residential	$ 264,546	$ 257,753	195,756	192,833
Commercial	148,416	146,581	121,557	120,989
Interruptible	5,040	4,676	5,003	4,539
Industrial	6,244	7,000	5,830	6,501
Total retail	424,246	416,010	328,146	324,862
Wholesale	142,167	93,221	223,084	154,884
Transportation	6,638	6,499	148,765	149,717
Other	4,182	4,825	438	443
Total	$ 577,233	$ 520,555	700,433	629,906

Natural gas revenues increased $56.7 million due to an increase in retail and wholesale natural gas revenues. The $8.2 million increase in retail natural gas revenues was due to higher retail rates (increased revenues $4.0 million) and increased volumes (increased revenues $4.2 million). We sold more retail natural gas in 2007 primarily due to customer growth. The increase in our wholesale revenues of $48.9 million was due to an increase in volumes (increased revenues $43.4 million) and an increase in prices (increased revenues $5.5 million). Wholesale sales reflect the balancing of loads and resources and the sale of resources in excess of load requirements as part of the natural gas procurement process. Any variance between the revenues and costs of the sale of resources in excess of load requirements is 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	
	2007	2006	2007	2006
Residential	306,737	300,940	273,415	267,345
Commercial	38,488	37,912	32,327	31,746
Interruptible	–	–	41	41
Industrial	1,378	1,388	261	254
Public street and highway lighting	426	425	–	–
Total retail customers	347,029	340,665	306,044	299,386

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

	2007	2006
Electric resource costs:		
Power purchased	$ 158,245	$ 150,719
Power cost amortizations, net of deferrals	3,641	29,259
Fuel for generation	125,043	109,723
Other fuel costs	16,454	50,881
Other regulatory amortizations, net	4,437	(6,199)
Other electric resource costs	14,417	12,597
Total electric resource costs	322,237	346,980
Natural gas resource costs:		
Natural gas purchased	433,140	371,142
Natural gas amortizations, net of deferrals	16,875	28,426
Other regulatory amortizations, net	8,746	5,098
Total natural gas resource costs	458,761	404,666
Total resource costs	$ 780,998	$ 751,646

Power purchased increased $7.5 million due to an increase in the price of power purchases (increased costs $12.6 million) due to overall increases in wholesale markets. This was partially offset by a decrease in the volume of power purchases (decreased costs $5.1 million) primarily due to increased thermal generation as well as decreased resource optimization activities as part of the process of balancing loads and resources. This was consistent with a decrease in wholesale sales volumes.

Net amortization of deferred power costs was $3.6 million for 2007 compared to $29.3 million for 2006 due to lower hydroelectric generation, higher purchased power and fuel costs and greater use of our thermal generating resources. During 2007, we recovered (collected as revenue) $31.0 million of previously deferred power costs in Washington and $5.7 million in Idaho. During 2007, we deferred $16.3 million of power costs in Washington and $16.7 million in Idaho, as power supply costs exceeded the amount included in base retail rates.

Fuel for generation increased $15.3 million due to higher natural gas fuel prices and an increase in thermal generation volumes (particularly Coyote Springs 2).

Other fuel costs decreased $34.4 million. This represents fuel that was purchased for generation, but was later sold when conditions indicated that it was not economic to use the fuel in generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel. Other fuel costs exceeded revenues we received from selling the natural gas. We account for this shortfall under the ERM in Washington and the PCA in Idaho. The decrease in other fuel costs was primarily due to an increased percentage of fuel used in generation and decreased resource optimization activities.

Other regulatory amortizations increased $10.6 million primarily due to the elimination of the BPA residential exchange credit.

The expense for natural gas purchased for sale to customers increased $62.0 million primarily due to an increase in total therms purchased. This was primarily due to an increase in wholesale sales as part of the balancing of loads and resources as part of the natural gas procurement process, and partially due to an increase in retail sales volumes. The increase was also partially due to an increase in natural gas prices. During 2007, we amortized $16.9 million of deferred natural gas costs compared to $28.4 million for 2006.

ADVANTAGE IQ

2008 compared to 2007

Net income for Advantage IQ was $6.1 million for 2008 compared to $6.7 million for 2007. Operating revenues increased $11.8 million and operating expenses increased $11.5 million. The increase in operating revenues was primarily due to the expansion of Advantage IQ's customer base and the third quarter acquisition of Cadence Network, partially offset by a decrease in interest revenue on funds held for customers (due to a decrease in interest rates). As of December 31, 2008, Advantage IQ had 537 customers representing 417,000 billed sites in North America, a significant increase from the end of 2007 primarily due to the acquisition of Cadence Network. The increase in operating expenses primarily reflects increased labor and other operational costs necessary to serve an expanding customer base, as well as the third quarter acquisition of Cadence Network (including the amortization of intangible assets). In 2008, Advantage IQ processed bills totaling $16.7 billion, an increase of $4.2 billion, or 34 percent, as compared to 2007. The acquisition of Cadence Network (in July 2008) added $2.1 billion in processed bills for 2008.

2007 compared to 2006

Net income for Advantage IQ was $6.7 million for 2007 compared to $6.3 million for 2006. Operating revenues increased $7.6 million and operating expenses increased $7.1 million. The increase in operating revenues was primarily due to the expansion of Advantage IQ's customer base as well as an increase in interest earnings on funds held for customers. As of December 31, 2007, Advantage IQ had 403 customers representing 199,000 billed sites in North America. The number of billed sites decreased slightly from December 31, 2006. This decrease was due to the loss of a customer that had a significant number of billed sites, and represented approximately 1 percent of annualized revenues. The increase in operating expenses primarily reflects increased labor and other operational costs necessary to serve an expanding customer base, which included consulting services. In 2007, Advantage IQ processed bills totaling $12.5 billion, an increase of $1.7 billion, or 16 percent, as compared to 2006.

OTHER BUSINESSES

2008 compared to 2007

Net loss from these operations was $2.5 million for 2008 compared to $12.0 million for 2007. Operating revenues decreased $37.1 million and operating expenses decreased $59.1 million. Contributing to the net loss in 2008 was losses on long-term venture fund investments and litigation costs. The net loss for 2007 and the decrease in operating revenues and expenses were primarily due to the sale of Avista Energy in 2007.

2007 compared to 2006

Net loss from these operations was $12.0 million for 2007 compared to net income of $8.9 million for 2006. Operating revenues decreased $116.6 million and operating expenses decreased $81.9 million. The net loss for 2007 and the decrease in operating revenues and expenses were primarily due to Avista Energy. The decline in results at Avista Energy in 2007 was primarily due to the underperformance on the power side of the business, losses on the power purchase agreement for the Lancaster Plant, and a loss on the sale of net assets to Shell Energy in June 2007.

NEW ACCOUNTING STANDARDS

Effective January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109," (FIN 48) which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. The adoption of FIN 48 did not have a cumulative effect on our financial statements. See Note 13 for further information.

Effective January 1, 2008, we adopted the provisions of SFAS No. 157, "Fair Value Measurements" related to its financial assets and liabilities and nonfinancial assets and liabilities measured at fair value on a recurring basis. In February 2008, the FASB issued Staff Position No. 157-2, which deferred the effective date for certain portions of SFAS No. 157 related to nonrecurring measurements of nonfinancial assets and liabilities. We will be required to adopt those provisions of SFAS No. 157 in 2009. The adoption of the provisions of SFAS No. 157 that became effective on January 1, 2008, did not have a material impact on our financial condition and results of operations. However, we expanded disclosures with respect to fair value measurements. See Note 22 for the expanded disclosures.

Effective January 1, 2008, we adopted SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option is elected would be reported in net income. We did not elect to use the fair value option under SFAS No. 159 for any financial assets and liabilities at implementation and as such the adoption of SFAS No. 159 did not have any impact on our financial condition and results of operations.

Effective January 1, 2008, we adopted FASB Staff Position (FSP) FIN 39-1, "Amendment of FASB Interpretation No. 39." FSP FIN 39-1 amends certain paragraphs of FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts, an interpretation of APB Opinion No. 10 and FASB Statement No. 105." This statement permits an entity to offset fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. As of December 31, 2008 we did not offset any fair value cash collateral receivables against net derivative positions.

Effective December 31, 2006, SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132 (R)" required us to recognize the overfunded or underfunded status of defined benefit postretirement plans in our Consolidated Balance Sheet measured as the difference between the fair value of plan assets and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plans, the benefit obligation is the accumulated postretirement benefit obligation. Previously, we only recognized the underfunded status of defined benefit pension plans as the difference between the fair value of plan assets and the accumulated benefit obligation. As we have historically recovered and currently recover our pension and other postretirement benefit costs related to our regulated operations in retail rates, we record a regulatory asset for that portion of our pension and other postretirement benefit funding deficiency. As such, the underfunded status of our pension and other postretirement benefit plans under SFAS No. 158 resulted in the recognition as of December 31, 2006 of:

- a liability of $60.1 million (associated deferred taxes of $21.0 million) for pensions and other postretirement benefits,
- a regulatory asset of $54.2 million (associated deferred taxes of $19.0 million) for pensions and other postretirement benefits,
- an increase to accumulated other comprehensive loss of $3.7 million (net of taxes of $2.1 million), and
- the removal of the intangible pension asset of $3.7 million (was included in other deferred charges).

As such, the total effect on the deferred income tax liability for the adoption of SFAS No. 158 was a net decrease of $2.1 million. The adoption of this statement did not have any effect on our net income.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations." This statement replaces SFAS No. 141 and addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. We will be required to begin applying this statement to any business combinations in 2009.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements." This statement amends Accounting Research Bulletin No. 51, "Consolidated Financial Statements" to establish accounting and reporting standards for noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. We will be required to adopt SFAS No. 160 in 2009. We do not expect the adoption of SFAS No. 160 to have any material impact on our financial condition and results of operations. However, it will impact the presentation and disclosure of noncontrolling (minority) interests in the consolidated financial statements. We are still in the process of evaluating the full impact SFAS No. 160 will have on our consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities." This statement will require disclosure of the fair value of derivative instruments and their gains and losses in a tabular format. The statement will also require disclosure of derivative features that are related to credit risk. We will be required to adopt SFAS No. 161 in 2009. We will have expanded disclosures with respect to derivatives and hedging activities.

In December 2008, the FASB issued FSP 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets." This FSP amends FASB statement No. 132(R) "Employer's Disclosures about Pensions and Other Postretirement Benefits." This statement provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. We will be required to adopt FSP 132(R)-1 at the end of 2009. We will have expanded disclosures with respect to our pension and other postretirement benefit plan assets.

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 the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" for our regulated utility operations. SFAS No. 71 requires us to reflect the effect of regulatory decisions in our financial statements. SFAS No. 71 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 statement 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 SFAS No. 71 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. In conjunction with the provisions of SFAS No. 133, the WUTC and the IPUC issued accounting orders authorizing us to offset any 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. As such, we do not recognize unrealized gains or losses on utility derivative commodity instruments in our Consolidated Statements of Income. We recognize realized gains or losses in the period of settlement, subject to regulatory 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 and the PCA mechanism. 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 periodically reviewed 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 12 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 $13.9 million for 2008, $14.3 million for 2007 and $14.5 million for 2006. Of our pension costs, approximately 65 percent are expensed and 35 percent are capitalized consistent with labor charges. 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 2008, the rates at which participants are assumed to retire by age were analyzed based upon historical trends and future projections. We revised the rates to assume that a greater percentage of participants would retire between the ages of 55 and 65. The assumed rates were revised to range from 5 percent to 40 percent and 100 percent at age 65. The previous rates ranged from 2 percent to 30 percent and 100 percent at age 65. The change resulted in an increase of $11.0 million to the pension benefit obligation as of December 31, 2008. The changes will also increase future years' pension costs.

We have not made any changes to pension plan provisions in 2008, 2007 and 2006 that have had any significant effect on our recorded pension plan amounts. We have revised the key assumption of the discount rate in 2008, 2007 and 2006. Such changes had an effect on our pension costs in 2008, 2007 and 2006 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. We decreased the pension plan discount rate in 2008 from 6.35 percent to 6.25 percent. In 2007 we used the 6.35 percentage rate for estimating our benefit obligation.

The assumed 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. The assumed long-term rate of return was 8.5 percent in each of 2008, 2007 and 2006. The actual return on plan assets, net of fees, was a loss of $63.2 million (or -25.5 percent) for 2008, a gain of $18.3 million (or 8.1 percent) for 2007 and a gain of $25.2 million (or 12.6 percent) for 2006. 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%	$ – *	$ 1,243
Expected long-term return on plan assets	+0.5%	– *	(1,243)
Discount rate	-0.5%	22,384	2,180
Discount rate	+0.5%	(20,179)	(1,983)

* *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, 2008 by $2.1 million and the service and interest cost by $0.2 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, 2008 by $1.8 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 financial statements based on the fair value of the equity or liability instruments issued. We measure (at the grant date) the estimated fair value of performance shares granted in accordance with the provisions of SFAS No. 123R. 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 with respect to the ultimate outcome of the respective matter. We account for contingencies in accordance with SFAS No. 5, “Accounting for Contingencies,” as well as other accounting guidance specific to a particular issue. In accordance with SFAS No. 5, 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 for the ultimate outcome of any particular contingency.

LIQUIDITY AND CAPITAL RESOURCES

REVIEW OF CASH FLOW STATEMENT

Overall – In April 2008, we issued $250.0 million of 5.95 percent First Mortgage Bonds due in 2018. The net proceeds from the issuance of $249.2 million (net of issuance discount and before Avista Corp.'s expenses), together with other available funds, were used to fund the $272.9 million of 9.75 percent Unsecured Senior Notes that matured on June 1, 2008. In December 2008, we issued $30.0 million of 7.25 percent First Mortgage Bonds due in 2013 and refinanced $17.0 million of Pollution Control Bonds. The proceeds from the $30.0 million issuance, together with funds borrowed under the $320.0 million committed line of credit, were used to fund $25.0 million of medium term notes that matured in December 2008 and $66.7 million of Pollution Control Bonds that we purchased in December 2008. During 2008, positive cash flows from operating activities of $115.6 million and a $252.2 million increase in short-term borrowings were used to fund the majority of our remaining cash requirements. These cash requirements included utility capital expenditures of $219.2 million, the cash settlement of interest rate swap agreements of $16.4 million and dividends of $37.1 million.

Operating Activities – Net cash provided by operating activities was $115.4 million for 2008 compared to $251.6 million for 2007. The overall decrease was due in part to the sale of Avista Energy's contracts and liquidation of Avista Energy's remaining net current assets that is reflected in the 2007 activity, payments made related to the settlement of water storage on Coeur d'Alene Tribe land, the increase in accounts receivable and the decrease in the amount of receivables that were sold. Net cash used by working capital components was $113.8 million for 2008, compared to cash provided of $80.9 million for 2007. The net cash used during 2008 primarily reflects a decrease in cash flows from:

- accounts receivable (representing an increase in the receivables outstanding and a $68.0 million decrease in the amount of receivables that were sold),
- deposits from counterparties (representing the return to counterparties of cash posted as collateral at Avista Utilities), and
- materials and supplies, fuel stock and natural gas stored (primarily representing an increase in natural gas that was stored).

This cash used was partially offset by positive cash flows from accounts payable (representing an increase in accounts payable).

The net cash provided during 2007 primarily reflects positive cash flows from:

- accounts receivable (representing net cash received from our customers primarily related to the liquidation of Avista Energy's receivables), and
- deposits with counterparties (representing the return from counterparties of cash posted as collateral at Avista Energy).

This cash provided was partially offset by negative cash flows from accounts payable (representing cash paid to our vendors primarily related to the liquidation of Avista Energy's payables) and deposits from counterparties (representing cash returned that was collateral funds from counterparties at Avista Utilities).

Significant non-cash items included $45.8 million of power and natural gas cost amortizations, net of deferrals, for 2008, an increase from $19.6 million for 2007. There was also an increase in the provision for deferred income taxes to $44.2 million for 2008 from a benefit of $7.4 million for 2007. Income tax payments (net of refunds) decreased to $10.0 million for 2008, compared to $29.4 million for 2007.

Investing Activities – Net cash used in investing activities was $185.3 million for 2008, a slight increase compared to $186.3 million for 2007. Utility property capital expenditures increased in 2008 as compared to 2007, and funds held from customers at Advantage IQ decreased. This was offset by a change in restricted cash. We liquidated $25.8 million of restricted cash in 2007 primarily representing the return of cash collateralizing energy contracts at Avista Energy.

The purchase of subsidiary minority interest of $6.6 million primarily represents the redemption of common stock from employees of Advantage IQ. Advantage IQ's employee stock incentive plan provides 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 upon the date of reacquisition.

Financing Activities – Net cash provided by financing activities was $82.4 million for 2008 compared to net cash used of $81.7 million for 2007. During 2008, our short-term borrowings increased $252.2 million, which reflects an increase in the amount of debt outstanding under our $320.0 million committed line of credit. Net proceeds from long-term debt issuances were $296.2 million in 2008 and common stock issuances increased to $28.6 million for 2008 (primarily $16.6 million from the issuance of 750,000 shares of common stock under a sales agency agreement). Debt maturities were $403.9 million and cash paid to settle interest rate swaps was $16.4 million in 2008. Cash dividends paid increased to $37.1 million (or 69.0 cents per share) for 2008 from $31.5 million (or 59.5 cents per share) for 2007. Additionally, customer funds obligations at Advantage IQ decreased by $30.8 million.

During 2007, our short-term borrowings decreased $4.0 million, which reflects a decrease in the amount of debt outstanding under our $320.0 million committed line of credit. Debt maturities were $26.7 million for 2007 and we redeemed the remaining $26.3 million of our preferred stock outstanding as required.

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 (including the recovery of previously deferred power and natural gas costs) from sales of electricity and natural gas. Significant uses of cash flows from our utility operations include the purchase of electricity 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 align our earned returns with those allowed by regulators. Effective January 1, 2008, the WUTC authorized an increase in our rates in Washington designed to increase annual electric revenues by $30.2 million and annual natural gas revenues by $3.3 million. Effective January 1, 2009, the WUTC authorized an increase in our rates in Washington designed to increase annual electric revenues by $32.5 million and annual natural gas revenues by $4.8 million. Effective October 1, 2008, the IPUC authorized an increase in our rates in Idaho designed to increase annual electric revenues by $23.2 million and annual natural gas revenues by $3.9 million. See further details in the section "Avista Utilities – Regulatory Matters."

With respect to 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 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 for our utility operations. We believe that we have adequate liquidity to meet the increased cash needs of higher energy commodity prices through our:

- $320.0 million committed line of credit,
- $200.0 million committed line of credit, and
- $85.0 million revolving accounts receivable sales facility.

As of December 31, 2008, we had a combined $313.7 million of available liquidity under the three facilities described above. We anticipate issuing long-term debt and common stock during 2009 to reduce the balances outstanding under our committed line of credit agreements. Additionally, we are planning to remarket or refund the $66.7 million of Pollution Control Bonds during 2009.

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 increase, 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 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 our credit ratings or adverse changes in market prices. 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, 2008, that we would have had to post additional collateral of approximately $163.0 million.

Our utility held cash deposits from other parties in the amount of $0.2 million as of December 31, 2008, a decrease from $12.5 million as of December 31, 2007. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral.

CAPITAL RESOURCES

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, consisted of the following as of December 31, 2008 and 2007 (dollars in thousands):

	December 31, 2008		December 31, 2007	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 17,207	0.8%	$ 427,344	21.6%
Short-term borrowings	252,200	11.5	–	–
Long-term debt to affiliated trusts	113,403	5.2	113,403	5.8
Long-term debt	809,258	37.0	521,489	26.4
Total debt	1,192,068	54.5	1,062,236	53.8
Stockholders' equity	996,883	45.5	913,966	46.2
Total	$ 2,188,951	100.0%	$ 1,976,202	100.0%

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 and natural gas costs, dividends and other requirements. Our stockholders' equity increased $82.9 million during 2008 primarily due to net income, other comprehensive income and the issuance of common stock under the sales agency agreement and other plans, 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, issuance of long-term debt and common stock issuance are expected to be the primary source of funds for operating needs, dividends and capital expenditures for 2009. Borrowings under our $320.0 million committed line of credit, $200.0 million committed line of credit and sales of accounts receivable under our $85.0 million revolving facility may supplement these funds to the extent necessary.

We do not have any scheduled long-term debt maturities in 2009. The current portion of long-term debt includes $17.0 million of Pollution Control Bonds because they are subject to purchase at any time at the option of the bond holder. We are planning to issue long-term debt and common stock during 2009 to repay a portion of the amounts that are outstanding on our credit agreement.

We have a committed line of credit in the total amount of $320.0 million with an expiration date of April 2011 with the following banks:

	Commitment (in millions)	
The Bank of New York Mellon	$	45.0
Union Bank of California, N.A.	$	45.0
Wells Fargo Bank, National Association	$	35.0
US Bank National Association	$	35.0
Keybank National Association	$	35.0
Bank of America, N.A.	$	30.0
Mizuho Corporate Bank, LTD	$	25.0
Comerica West Incorporated	$	20.0
Goldman Sachs Credit Partners, L.P.	$	15.0
Societe Generale	$	15.0
First Commercial Bank, New York	$	10.0
Bank Hapoalim B.M., New York Branch	$	10.0

Under the agreement, we can request the issuance of up to $320.0 million in letters of credit. As of December 31, 2008, we had $250.0 million in borrowings outstanding under this committed line of credit, an increase from no borrowings outstanding as of December 31, 2007. As of December 31, 2008, there were $24.3 million in letters of credit outstanding, a decrease from $34.8 million as of December 31, 2007. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds issued to the agent bank. Such First Mortgage Bonds would only become due and payable in the event, and then only to the extent, that we default on obligations under the committed line of credit.

Additionally, in November 2008, we entered into a new committed line of credit in the total amount of $200.0 million with an expiration date of November 2009 with the following banks:

	Commitment (in millions)	
Union Bank of California, N.A.	$	44.25
Wells Fargo Bank, National Association	$	44.25
JPMorgan Chase Bank, N.A.	$	26.50
Keybank National Association	$	22.00
Suntrust Bank	$	22.00
US Bank National Association	$	17.50
The Bank of New York Mellon	$	13.50
UBS Loan Finance LLC	$	10.00

As of December 31, 2008, we did not have any borrowings outstanding under this committed line of credit. The committed line of credit is secured by $200.0 million of non-transferable First Mortgage Bonds issued to the agent bank. Such First Mortgage Bonds would only become due and payable in the event, and then only to the extent, that we default on obligations under the committed line of credit.

Our committed line of credit agreements contain customary covenants and default provisions, including a covenant requiring 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, 2008, we were in compliance with this covenant with a ratio of 3.27 to 1. The committed line of credit agreements also have a covenant which does 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, 2008, we were in compliance with this covenant with a ratio of 54.5 percent. If the proposed change in organization to a holding company structure becomes effective, the committed line of credit agreements will remain at Avista Corp. (Avista Utilities). See "Note 28 of the Notes to Consolidated Financial Statements" for further information on the proposed change in organization to a holding company structure. The committed line of credit agreements also have a covenant which requires the Company to maintain a minimum funded ratio of the pension plan assets to liabilities. The Pension Protection Act of 2006 (that was implemented in 2008) modified the liability calculation utilized to calculate the funded ratio. Avista Corp. amended the covenant related to the pension funded ratio, under its $320.0 million committed line of credit agreement, to conform with the calculations under the Pension Protection Act of 2006.

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. We do not guarantee the indebtedness of any of our subsidiaries. As of December 31, 2008, Avista Corp. and our subsidiaries were in compliance with all of the covenants of our financing agreements.

We are restricted under our Restated Articles of Incorporation as to the additional preferred stock we can issue. As of December 31, 2008, we could issue $706.2 million of additional preferred stock at an assumed dividend rate of 6.95 percent.

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

provided, however, that 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, 2008, our property additions and retired bonds would have entitled us to issue $688.9 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, 2008, the net earnings test would limit the principal amount of additional bonds we could issue to $545.9 million. We believe that we have adequate capacity to issue First Mortgage Bonds to meet our financing needs over the next several years.

In December 2005, the WUTC issued an order approving the settlement agreement reached in our Washington general rate case with certain conditions. We agreed to increase the utility equity component to 35 percent by the end of 2007 and to 38 percent by the end of 2008. Our utility equity component met this target as it was approximately 47.6 percent as of December 31, 2008.

In December 2006, we entered into a sales agency agreement with a sales agent to issue up to 2 million shares of our common stock from time to time. We issued 750,000 shares of common stock (total net proceeds of $16.6 million) under this sales agency agreement during the third quarter of 2008. These were our first issuances under the sales agency agreement. We will continue to evaluate issuing common stock in future periods.

OFF-BALANCE SHEET ARRANGEMENTS

Avista Receivables Corporation (ARC) is our wholly owned, bankruptcy-remote subsidiary formed for the purpose of acquiring or purchasing interests in certain of our accounts receivable, both billed and unbilled. On March 14, 2008, Avista Corp., ARC and Bank of America, N.A. amended a Receivables Purchase Agreement. The most significant amendment was to extend the termination date from March 17, 2008 to March 13, 2009.

The Receivables Purchase Agreement was originally entered into on May 29, 2002 and provides us with cost-effective funds for:

- working capital requirements,
- capital expenditures, and
- other general corporate needs.

Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of our receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of our ommitted line of credit agreements. As of December 31, 2008, we had the ability to sell up to $85.0 million of receivables and there was $17.0 million in accounts receivable sold under this revolving agreement. We expect to renew this facility before the March 13, 2009 expiration.

SPOKANE ENERGY, LLC

In December 1998, we received cash proceeds of $143.4 million from a transaction in which we assigned and transferred certain rights under a long-term power sales contract with Portland General Electric Company (PGE) to a funding trust. Pursuant to orders from the WUTC and the IPUC, we fully amortized this amount by the end of 2002.

Under this power exchange arrangement, Peaker, LLC (Peaker) purchases capacity from our utility and sells capacity to Spokane Energy LLC (Spokane Energy), our unconsolidated subsidiary formed in 1998 solely for the purpose of facilitating a long-term capacity contract between PGE and Avista Corp. Spokane Energy sells the related capacity to PGE. Peaker acts as an intermediary to fulfill certain regulatory requirements between Spokane Energy and Avista Corp. The transaction is structured such that Spokane Energy bears full recourse risk for a loan (balance of $80.7 million as of December 31, 2008) that matures in January 2015. We have no recourse related to this loan. Peaker makes monthly payments (which are not material to our financial statements) to us for its capacity purchase.

CREDIT RATINGS

The following table summarizes our credit ratings as of February 27, 2009:

	Standard & Poor's (1)	Moody's (2)	Fitch, Inc. (3)
Avista Corporation			
Corporate/Issuer rating	BBB-	Baa3	BB+
Senior secured debt (4)	BBB+	Baa2	BBB
Senior unsecured debt	BBB-	Baa3	BBB-
Preferred stock	BB	Ba2	BB+
Avista Capital II (5)			
Preferred Trust Securities	BB	Ba1	BB+
AVA Capital Trust III (5)			
Preferred Trust Securities	BB	Ba1	BB+
Rating outlook	Stable	Stable	Positive

(1) *Ratings were upgraded in February 2008.*

(2) *Ratings were upgraded in December 2007.*

(3) *Ratings were upgraded in August 2007 and affirmed in February 2008.*

(4) *Based on our understanding of the methodology currently used by Standard & Poor's, the rating on senior secured debt may depend on, among other things, the amount of our utility property (net of depreciation) relative to the amount of such debt outstanding and the amount currently issuable. Thus, the rating on senior secured debt as of any particular time may depend on factors affecting our utility property accounts, as well as factors affecting the principal amount of such debt issued and issuable, including factors affecting our net income.*

(5) *Only assets are subordinated debentures of Avista Corporation.*

Each security rating agency has its own methodology for assigning ratings. Security ratings are not recommendations to buy, sell or hold securities. The ratings are subject to change or withdrawal at any time by the respective credit rating agencies. Each credit rating should be evaluated independently of any other ratings.

PENSION PLAN

As of December 31, 2008, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. We contributed $28 million to the pension plan in 2008 and $15 million in both 2006 and 2007. Our total pension plan contributions were $112 million from 2002 through 2008. Due to market conditions and the decline in the fair value of pension plan assets, we plan to contribute $48 million to the pension plan in 2009. 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 projected benefit obligation). We have adequate liquidity to meet our pension plan funding obligations for 2009.

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 contained in our Restated Articles of Incorporation, as amended.

On February 13, 2009, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.18 per share on the Company's common stock.

As further discussed at "Note 28 of the Notes to the Consolidated Financial Statements," the IPUC accepted a stipulation that we entered with the IPUC Staff that sets forth a variety of conditions if and when we implement a holding company structure. One of the conditions would require IPUC approval of any dividend to the holding company that would reduce utility common equity below 25 percent. We entered into a similar agreement in Washington. This agreement would require WUTC approval of any dividend to the holding company that would reduce utility common equity below 30 percent. The utility equity component was approximately 47.6 percent as of December 31, 2008.

AVISTA UTILITIES OPERATIONS

Capital expenditures for our utility were $586.3 million for the years 2006 through 2008. We expect utility capital expenditures to be over $210 million for each of 2009, 2010 and 2011. In addition to ongoing needs for our distribution system, significant projects include upgrades to generating facilities. 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. There are no scheduled long-term debt maturities in 2009 and $35.0 million of scheduled maturities in 2010.

Two series of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds became subject to remarketing in

December 2008. The $66.7 million series was purchased by us and we expect that at a later date, subject to market conditions, these bonds will be remarketed to unaffiliated investors or refunded by a new issue. The $17.0 million series was refunded by a new issue.

See "Notes 6, 15, 16, 17, 18, 21, 22 and 23 of Notes to Consolidated Financial Statements" for additional details related to our financing activities.

We are committed to investment in generation, transmission and distribution systems with a focus on increasing capacity and improving reliability. We continue to upgrade hydroelectric plants to increase their availability and capture additional output.

In the second quarter of 2008, we completed the acquisition of a wind generation site. We expect to construct a 50 MW generation facility at an estimated cost of over $125 million with the majority of the costs expected to be incurred in 2013 and thereafter. Future generation resource decisions will be impacted by legislation for restrictions on greenhouse gas emissions and renewable energy requirements as discussed at "Environmental Issues and Other Contingencies."

We are participating in planning activities for the development of a proposed 3,000 MW transmission project that would extend from British Columbia, Canada to Northern California. Other participants include Pacific Gas and Electric Company, PacifiCorp, and British Columbia Transmission Corporation. We have executed an agreement (stage one agreement) with the other participants in order to perform preliminary studies and assessments for the project, including electrical system studies and resource mapping of possible transmission line corridors. Under the stage one agreement, we have committed to contribute $0.6 million, or 12.25 percent of the total stage one costs of the project.

ADVANTAGE IQ OPERATIONS

Capital expenditures for Advantage IQ were $8.2 million for the years 2006 through 2008. We do not expect capital expenditures for the years 2009 through 2011 for Advantage IQ to be significant to our consolidated cash flows and financial condition. However, they are expected to be higher than past years to improve technology that will support continued growth and reliable service to customers. These capital expenditures should be funded by Advantage IQ's cash flows from operations. As of December 31, 2008, Advantage IQ had $0.1 million of debt outstanding related to capital leases.

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. This plan was amended to provide liquidity to participants of Advantage IQ's stock option plan. As the repurchase feature is at the discretion of the minority shareholders and option holders, a liability of $10.4 million was outstanding as of December 31, 2008 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock. Additionally, Advantage IQ has a liability of $28.8 million 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 of the Notes to Consolidated Financial Statements for further information). As of December 31, 2007, this liability was $14.0 million. During 2008, $6.6 million of common stock was repurchased from Advantage IQ employees.

In February 2008, Advantage IQ entered into a $12.5 million committed credit agreement with a bank that has an expiration date of February 2011. Advantage IQ has the ability to increase the credit facility to $25 million under the same agreement. The credit agreement is secured by substantially all of Advantage IQ's assets. Advantage IQ had $2.2 million of borrowings outstanding under the credit agreement as of December 31, 2008.

OTHER OPERATIONS

Capital expenditures for these companies were $2.3 million for the years 2006 through 2008. We do not expect capital expenditures for the years 2009 through 2011 for these companies to be significant to our consolidated cash flows and financial condition. As of December 31, 2008, these companies had $2.8 million of long-term debt outstanding.

CONTRACTUAL OBLIGATIONS

The following table provides a summary of our future contractual obligations as of December 31, 2008 (dollars in millions):

	2009	2010	2011	2012	2013	Thereafter
Avista Utilities:						
Long-term debt maturities (1)	$ 17	$ 35	$ –	$ 7	$ 75	$ 706
Long-term debt to affiliated trusts	–	–	–	–	–	113
Interest payments on long-term debt (2)	56	55	53	53	52	666
Short-term borrowings	250	–	–	–	–	–
Energy purchase contracts (3)	410	222	163	133	113	864
Public Utility District contracts (3)	5	3	3	3	2	34
Operating lease obligations (4)	1	–	–	–	–	2
Other obligations (5)	25	28	26	29	30	247
Payments to Coeur d'Alene Tribe	10	4	–	–	–	–
Information services contracts	15	15	15	15	15	–
Pension plan funding (6)	48	21	21	31	31	–
Avista Capital (consolidated):						
Long-term debt	–	–	–	–	–	3
Short-term debt	2	–	–	–	–	–
Energy purchase contracts (7)	22	27	27	27	26	290
Venture funds investments (8)	3	2	–	–	–	–
Operating lease obligations (4)	3	2	–	–	–	1
Total contractual obligations	$ 867	$ 414	$ 308	$ 298	$ 344	$ 2,926

(1) We do not have any scheduled long-term debt maturities in 2009. The obligation for 2009 includes $17 million of bonds because they are subject to purchase at any time at the option of the bond holder.

(2) 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, 2008.

(3) 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.

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

(5) Represents operational agreements, settlements and other contractual obligations with respect to generation, transmission and distribution facilities. These costs are generally recovered through base retail rates.

(6) Represents our estimated cash contributions to the pension plan through 2013. We cannot reasonably estimate pension plan contributions beyond 2013 at this time.

(7) These contractual commitments are primarily related to the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were assigned by Avista Energy to Shell Energy through the end of 2009. Beginning in 2010 through 2026, the rights and obligations of the power purchase agreement for the Lancaster Plant are contracted to Avista Energy. We expect these rights and obligations will be transferred to our regulated utility, subject to future approval by the WUTC and the IPUC.

(8) Represents our 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, including any payments related to uncertain tax positions. The timing of the payments on uncertain tax positions is not reasonably determinable.

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.

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 under authority of The Energy Policy Act of 1992 and other federal laws. The FERC 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.

We actively monitor and participate, as appropriate in energy industry developments, to maintain and enhance the ability to effectively participate in wholesale energy markets consistent with our business goals.

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 the 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.

BUSINESS RISK

Primarily through our utility operations, we are exposed to risks including, but not limited to:

- global financial and economic conditions (including the availability of credit) and their effect on our ability to obtain funding for working capital and long-term capital requirements on acceptable terms,
- economic conditions in our service areas, including the effect on the demand for, and customers' ability to pay for, our utility services,
- streamflow and weather conditions that impact hydroelectric generation, utility operations and customer demand,
- market prices and supply of wholesale energy, which we purchase and sell, including power, fuel and natural gas,
- regulatory disallowance of the recovery of power and natural gas costs, operating costs and capital investments and the allowance of a reasonable rate of return on investment,
- the effects of changes in legislative and governmental regulations, including restrictions on emissions from generating plants and requirements for the acquisition of new resources,
- changes in regulatory requirements,
- availability of generation facilities,
- customer response to rate increases, and
- competition.

Also, like other utilities, our facilities and operations are exposed to natural disasters and terrorism risks or other malicious acts. In addition, the energy business exposes us to the financial, liquidity, credit and price risks associated with wholesale purchases and sales of energy commodities. See further reference to risks and uncertainties under "Forward-Looking Statements."

We have mechanisms in each regulatory jurisdiction that provide for recovery of the majority of the changes in 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 in Washington, are deferred on our Consolidated Balance Sheets for the opportunity for recovery through future retail rates. These deferred power and natural gas costs are subject to review for prudence and recoverability and as such certain deferred costs may be disallowed by the respective regulatory agencies.

Our hydroelectric generation was 99 percent of normal in 2008. Our hydroelectric generation was below normal (based on a 70-year average) for seven of the past nine 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 in recent years 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. This reduces the risk of these customers by-passing our system in the foreseeable future and minimizes the impact on our earnings.

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, 2008, 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 26 of the Notes to Consolidated Financial Statements" for further information with respect to the refund proceedings.

We engage in wholesale sales and purchases of energy commodities and, accordingly, are subject to commodity price risk, credit risk and other risks associated with these activities.

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".

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.

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

- amount of North American production and production capacity that can be delivered to our service areas,
- level of imports and exports, particularly from Canada by pipeline and to a growing extent by LNG,
- 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. 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.

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, and
- 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.

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.

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.

Other Operational and Event Risks

We are subject to various operational and event risks, which are common to the utility industry, including:

- blackouts or disruptions to our distribution, transmission or transportation systems,
- forced outages at generating plants,
- fuel quality and availability,
- disruptions to information systems and other administrative resources required for normal operations, and
- weather conditions and natural disasters that can cause physical damage to our property, requiring repairs to restore utility service.

Terrorism and other malicious threats are a risk to the entire utility industry. Potential disruptions to operations or destruction of facilities from terrorism or other malicious acts are not readily determinable. We have taken various steps to mitigate terrorism risks and prepare contingency plans in the event that our facilities are targeted.

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 risk by taking advantage of market conditions when timing the issuance of long-term financings and optional debt redemptions and through the use of fixed rate long-term debt with varying maturities. The interest rate on $51.5 million of long-term debt to affiliated trusts is adjusted quarterly, reflecting current market rates. We also have $17.0 million of Pollution Control Bonds with interest rates that adjust daily. Additionally, amounts borrowed under our $320.0 million and $200.0 million committed line of credit agreements have variable interest rates.

In December 2008, we entered into two interest rate swap agreements, totaling $50.0 million, to manage the risk that changes in interest rates may affect the amount of future interest payments. These interest rate swap agreements relate to the anticipated issuances of debt in 2009. Under the terms of these agreements, the value of the interest rate swaps is determined based upon us paying a fixed rate and receiving a variable rate based on LIBOR. These interest rate swap agreements are considered hedges against fluctuations in future cash flows associated with changes in interest rates. As of December 31, 2008, we had a derivative asset of $0.9 million. We estimate that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2008 would increase this derivative asset by $0.4 million, while a 10-basis-point decrease would decrease the asset by $0.4 million.

In January 2009, the Company entered into two interest rate swaps totaling $50.0 million, to manage the risk that changes in interest rates may affect the amount of future interest payments. These interest rate swap agreements relate to the anticipated issuances of debt in 2009.

Foreign Currency Risk

A significant portion of our natural gas supply is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars which avoids foreign currency risk. A growing 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. In early 2009, we implemented a process to 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.

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 established a 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.

We also operate with 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. 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 to sell projected resource surpluses and obtain resources when deficits are projected. We buy and sell fuel for thermal generation facilities based on comparative power market prices and marginal costs of fueling and operating available generating facilities and the relative economics of substitute market purchases for generating plant operation.

To reduce the impact on our operations of energy market price volatility such as the significant wholesale energy market price changes experienced in 2008, we have initiated longer-term hedging practices for electricity (including fuel for generation) and natural gas. Executing this extended hedging program may increase our credit risks, particularly in consideration of the national economic conditions with resultant financial stress among energy market participants. 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 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.

ECONOMIC AND UTILITY LOAD GROWTH

Along with others in our utility service area, we encourage regional economic development, including expanding existing businesses and attracting new businesses to the Inland Northwest and Southwest Oregon region. Agriculture, mining and lumber were the primary industries for many years; today health care, education, finance, electronic and other manufacturing, tourism and the service sectors have grown in importance in our utility service area.

Based on our forecast for electric customer growth to average 1.8 to 2.0 percent and natural gas customer growth to average 2.5 to 2.7 percent within our service area, we anticipate retail electric and natural gas load growth will average between 1.5 and 2.5 percent annually for the four year period 2009-2012. This forecast of load growth is a decline as compared to our forecast in the prior year. While the number of electric customers is growing, the average annual usage by each residential electric customer has stabilized. Natural gas sales growth has slowed as retail prices have risen 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 projections 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 forward-looking projections.

SUCCESSION PLANNING

Maintaining our culture, mission, and long-term strategy by having a strong succession planning and management development process is one of our key strategic initiatives. Our executive officer team continues to work towards ensuring that an effective succession planning process is in place for the best interests of our future. We have implemented bench strength analysis in our management group as well as in key technical and craft areas. The focus is on organizational leadership capability as well as technical proficiency in complex jobs. We have implemented development plans for future successors that identify areas of strengths and weaknesses. Development plans provide action steps that provide new opportunities to work towards ensuring that successor candidates have the needed experience. We believe that our succession planning process, coupled with market based recruitment, provides the right structure to assure that we have the ability to fill vacancies with personnel having adequate training and experience.

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 an ownership interest are designed and operated in compliance with applicable environmental laws.

We monitor legislative and regulatory developments at all levels of government with respect to 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 costs of generating plants,
- increase the lead time for the construction of new generating plants,
- require modification of our existing generating plants,
- require existing generating plants to be curtailed or shut down,

- increase the risk of delay on construction projects,
- reduce the amount of energy available from our generating plants, and
- restrict the types of generating plants that can be built.

As such, compliance with such environmental laws and regulations could result in increases to capital expenditures and operating expenses. However, we intend to seek recovery of incurred costs through the rate making process.

Rising concerns about long-term global climate changes could have a significant effect on our business. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of hydroelectric generation capacity. Changing temperatures could also increase or decrease customer demand. 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.

Greenhouse gas requirements could result in significant costs for us to comply with restrictions on carbon dioxide or other greenhouse gas emissions. Such requirements could also preclude us from developing certain types of generating plants.

We continue to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas requirements. In particular, a greenhouse gas bill was passed by the legislature in the state of Washington and bills have been introduced in the U. S. Senate and House of Representatives. There will most likely be continuing activity in the near future.

In February 2007, the Governors of Arizona, California, New Mexico, Oregon and Washington started the Western Climate Initiative (WCI) for the purpose of developing regional strategies to address climate change. The Governors of Utah and Montana, and the Premiers of British Columbia, Manitoba, Ontario and Quebec subsequently joined the WCI. In August 2007, the WCI partners set an overall regional goal for reducing greenhouse gas emissions to 15 percent below 2005 levels by 2020. In September 2008, the WCI partners announced recommendations for the design of a regional market-based cap-and-trade program to help achieve this reduction goal. The program will require emitters to cut their greenhouse gas levels by setting a limit (cap) on emissions and then allowing the market to identify the least-cost ways to achieve the limit. These emissions goals were codified under Washington law with the passage of HB 2815 in March 2008. This greenhouse gas bill sets goals to reduce emissions in the state of Washington to 1990 levels by 2020; to 25 percent below 1990 levels by 2035; and to 50 percent below 1990 levels by 2050.

A bill was introduced in January 2009 before the Washington State Legislature to confer authority to the Washington State Department of Ecology (DOE) to implement and enforce a cap and trade regulatory regime. The legislation requires all DOE rules "must be consistent with the regional cap and trade program" designed by the WCI participants. The legislation is currently pending before the Washington State Legislature and outcome is uncertain at this time.

A greenhouse gas emissions performance standard (SB 601) passed into law in the state of Washington during 2007. This law places significant restrictions on greenhouse gas emissions from any new generation plants built in the state of Washington. Furthermore, the bill intends to prevent utilities from entering into long-term contracts (five years or more) to purchase energy produced by plants in other states that do not meet the same restrictions. Currently, the only type of non-renewable base load thermal generating plants that meet these restrictions are natural gas-fired combined-cycle combustion turbines.

Initiative Measure 937 (I-937), the Energy Independence Act, was passed into law through the General Election in Washington in November 2006. I-937 requires investor-owned, cooperative, and government-owned electric utilities with over 25,000 customers to acquire new 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 beginning in 2012. 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 resources and/or renewable credits.

Our most recent Electric Integrated Resource Plan (IRP), which we filed with the WUTC and the IPUC in August 2007, includes the acquisition of additional renewable resources such that, if the IRP is implemented, we would be compliant with the requirement by the various milestone dates. The IRP outlines a preferred resource strategy that calls for 350 MW of natural gas generation, 300 MW of wind generation, 87 MW of conservation, 38 MW of hydroelectric generation plant upgrades and 35 MW of other renewable generation by 2017. The amount of renewable resources in our future IRPs could change if the cost effectiveness of those resources changes.

In October 2007, we became a member of the Chicago Climate Exchange (CCX), North America's only voluntary, verifiable and legally binding emissions reduction and trading marketplace for all six greenhouse gases. Members agree to reduce their greenhouse gas emissions by 6 percent from an established baseline by 2010. The CCX allows participants who exceed their reduction targets to bank or sell the excess CCX Carbon Financial Instruments. The audit establishing our 2007 baseline emissions was completed in July 2008. We received credit for 1,470 CCX Carbon Financial Instruments in October 2008.

For other environmental issues and other contingencies see "Note 26 of the Notes to Consolidated Financial Statements."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: – Business Risk and – Risk Management," "Note 7 of the Notes to Consolidated Financial Statements" and "Note 22 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.

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, 2008 and 2007, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 2 to the consolidated financial statements ("Note 2"), during 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109.* Additionally, as described in Note 2, during 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

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, 2008, 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 27, 2009, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 27, 2009

CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Years Ended December 31

Dollars in thousands, except per share amounts

	2008	2007	2006
Operating Revenues:			
Utility revenues	$ 1,572,664	$ 1,288,363	$ 1,267,938
Non-utility energy marketing and trading revenues	25,225	61,541	177,551
Other non-utility revenues	78,874	67,853	60,822
Total operating revenues	1,676,763	1,417,757	1,506,311
Operating Expenses:			
Utility operating expenses:			
Resource costs	1,031,989	780,998	751,646
Other operating expenses	206,528	198,778	187,457
Depreciation and amortization	87,845	86,091	81,904
Taxes other than income taxes	72,057	72,443	69,882
Non-utility operating expenses:			
Resource costs	23,553	68,676	144,137
Other operating expenses	65,093	67,783	66,546
Depreciation and amortization	4,787	4,559	5,179
Total operating expenses	1,491,852	1,279,328	1,306,751
Income from operations	184,911	138,429	199,560
Other Income (Expense):			
Interest expense	(73,446)	(79,142)	(89,051)
Interest expense to affiliated trusts	(6,141)	(7,298)	(7,116)
Capitalized interest	4,612	3,864	2,934
Regulatory disallowance of unamortized debt repurchase costs	–	(3,850)	–
Other income – net	9,309	10,806	8,600
Total other income (expense) – net	(65,666)	(75,620)	(84,633)
Income before income taxes	119,245	62,809	114,927
Income taxes	45,625	24,334	41,986
Net income	$ 73,620	$ 38,475	$ 72,941
Weighted-average common shares outstanding (thousands), basic	53,637	52,796	49,162
Weighted-average common shares outstanding (thousands), diluted	54,028	53,263	49,897
Total earnings per common share, basic (Note 24)	$ 1.37	$ 0.73	$ 1.48
Total earnings per common share, diluted (Note 24)	$ 1.36	$ 0.72	$ 1.46
Dividends paid per common share	$ 0.690	$ 0.595	$ 0.570

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

	2008	2007	2006
Net income	$ 73,620	$ 38,475	$ 72,941
Other Comprehensive Income (Loss):			
Foreign currency translation adjustment	–	1,010	(38)
Reclassification adjustment for foreign currency translation adjustment included in loss on sale of contracts	–	(2,379)	–
Unrealized gains (losses) on interest rate swap agreements – net of taxes of $(2,063), $(1,874) and $436, respectively	(3,831)	(3,480)	810
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 and $1,308	10,657	–	2,430
Change in unfunded benefit obligation for pension plan – net of taxes of $3,602, $1,642 and $4,023, respectively	6,690	3,050	7,472
Unrealized losses on derivative commodity instruments – net of taxes of $(324) and $(555), respectively	–	(602)	(1,030)
Reclassification adjustment for realized gains on derivative commodity instruments included in net income – net of taxes of $(136) and $(294), respectively	–	(253)	(546)
Reclassification adjustment for realized losses on derivative commodity instruments included in loss on sale of contracts, net of taxes of $464	–	862	–
Reclassification adjustment for realized losses on investment securities included in net income – net of taxes of $43	–	–	80
Unrealized investment losses – net of taxes of $(9)	–	–	(16)
Total other comprehensive income (loss)	13,516	(1,792)	9,162
Comprehensive income	$ 87,136	$ 36,683	$ 82,103

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation
As of December 31
Dollars in thousands

	2008	2007
Assets:		
Current Assets:		
Cash and cash equivalents	$ 24,313	$ 11,839
Restricted cash	–	4,068
Accounts and notes receivable-less allowances of $45,062 and $42,582	218,846	105,440
Utility energy commodity derivative assets	11,234	12,078
Regulatory asset for utility derivatives	60,229	7,171
Funds held for customers	59,095	89,885
Materials and supplies, fuel stock and natural gas stored	53,526	34,985
Deferred income taxes	18,561	20,251
Income taxes receivable	22,769	30,025
Other current assets	13,654	16,443
Total current assets	482,227	332,185
Net Utility Property:		
Utility plant in service	3,343,535	3,131,916
Construction work in progress	77,487	100,106
Total	3,421,022	3,232,022
Less: Accumulated depreciation and amortization	928,831	880,680
Total net utility property	2,492,191	2,351,342
Other Property and Investments:		
Investment in exchange power – net	26,133	28,583
Investment in affiliated trusts	13,403	13,403
Other property and investments – net	99,340	74,171
Total other property and investments	138,876	116,157
Deferred Charges:		
Regulatory assets for deferred income tax	115,005	117,461
Regulatory assets for pensions and other postretirement benefits	172,278	51,006
Other regulatory assets	85,112	43,004
Non-current utility energy commodity derivative assets	49,313	55,313
Power and natural gas deferrals	57,607	85,885
Unamortized debt expense	33,004	32,542
Other deferred charges	5,134	4,902
Total deferred charges	517,453	390,113
Total assets	$ 3,630,747	$ 3,189,797

The Accompanying Notes are an Integral Part of These Statements.

Avista Corporation
As of December 31
Dollars in thousands

	2008	2007
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Accounts payable	$ 176,116	$ 117,546
Customer fund obligations	59,095	89,885
Current portion of long-term debt	17,207	427,344
Short-term borrowings	252,200	–
Interest accrued	10,871	12,578
Utility energy commodity derivative liabilities	71,463	19,249
Other current liabilities	101,592	97,047
Total current liabilities	688,544	763,649
Long-term debt	809,258	521,489
Long-term debt to affiliated trusts	113,403	113,403
Other Non-Current Liabilities and Deferred Credits:		
Regulatory liability for utility plant retirement costs	213,747	209,357
Non-current regulatory liability for utility derivatives	42,172	53,414
Pensions and other postretirement benefits	184,588	90,555
Deferred income taxes	488,940	440,918
Other non-current liabilities and deferred credits	93,212	83,046
Total other non-current liabilities and deferred credits	1,022,659	877,290
Total liabilities	2,633,864	2,275,831
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 54,487,574 and 52,909,013 shares outstanding	774,986	726,933
Accumulated other comprehensive loss	(6,092)	(19,608)
Retained earnings	227,989	206,641
Total stockholders' equity	996,883	913,966
Total liabilities and stockholders' equity	$ 3,630,747	$ 3,189,797

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Increase (Decrease) in Cash and Cash Equivalents
Avista Corporation
For the Years Ended December 31
Dollars in thousands

	2008	2007	2006
Operating Activities:			
Net income	$ 73,620	$ 38,475	$ 72,941
Non-cash items included in net income:			
Depreciation and amortization	92,632	90,650	87,083
Provision (benefit) for deferred income taxes	44,161	(7,369)	(19,212)
Power and natural gas cost amortizations, net of deferrals	45,836	19,630	56,327
Regulatory disallowance of unamortized debt repurchase costs	–	3,850	–
Amortization of debt expense	4,673	6,345	7,741
Write-offs and impairments of assets	–	2,290	–
Unrealized loss (gain) on energy commodity derivatives	–	24,594	(1,510)
Loss on sale of Avista Energy assets	–	4,254	–
Equity-related AFUDC	(5,692)	(4,736)	(2,429)
Other	(868)	(7,265)	(16,018)
Payments for settlement of water storage on Coeur d'Alene Tribe land	(25,187)	–	–
Changes in working capital components:			
Accounts and notes receivable	(116,714)	180,488	219,071
Materials and supplies, fuel stock and natural gas stored	(18,541)	4,522	11,698
Deposits with counterparties	–	79,477	(20,123)
Other current assets	(10,494)	7,589	(46,477)
Accounts payable	47,669	(170,478)	(225,499)
Deposits from counterparties	(12,290)	(28,983)	27,769
Other current liabilities	(3,427)	8,308	50,104
Net cash provided by operating activities	115,378	251,641	201,466
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(219,239)	(205,811)	(161,266)
Proceeds from sale of utility property claim	–	–	5,484
Other capital expenditures	(3,459)	(3,280)	(3,819)
Purchase of auction rate investment securities	–	(130,000)	–
Sale of auction rate investment securities	–	130,000	–
Decrease (increase) in restricted cash	4,068	25,834	(4,269)
Purchase of subsidiary minority interest	(6,624)	–	–
Cash paid by subsidiary for acquisition, net of cash received	(1,440)	–	–
Decrease (increase) in funds held for customers	30,790	249	(51,865)
Proceeds from asset sales	7,998	441	25,706
Other	2,561	(3,761)	(1,551)
Net cash used in investing activities	(185,345)	(186,328)	(191,580)

The Accompanying Notes are an Integral Part of These Statements.

Increase (Decrease) in Cash and Cash Equivalents
Avista Corporation
For the Years Ended December 31
Dollars in thousands

	2008	2007	2006
Financing Activities:			
Increase (decrease) in short-term borrowings	$ 252,200	$ (4,000)	$ (59,494)
Proceeds from issuance of long-term debt	296,165	–	149,778
Redemption and maturity of long-term debt	(403,856)	(26,738)	(199,018)
Premiums paid for the redemption of long-term debt	–	–	(426)
Long-term debt and short-term borrowing issuance costs	(5,024)	(165)	(5,436)
Cash paid in interest rate swap agreement	(16,395)	–	(3,738)
Redemption of preferred stock	–	(26,250)	(1,750)
Issuance of common stock	28,565	4,977	88,585
Cash dividends paid	(37,071)	(31,451)	(27,927)
Increase (decrease) in customer fund obligations	(30,790)	(249)	51,865
Other	(1,353)	2,160	–
Net cash provided by (used in) financing activities	82,441	(81,716)	(7,561)
Net increase (decrease) in cash and cash equivalents	12,474	(16,403)	2,325
Cash and cash equivalents at beginning of period	11,839	28,242	25,917
Cash and cash equivalents at end of period	$ 24,313	$ 11,839	$ 28,242
Supplemental Cash Flow Information:			
Cash paid during the period:			
Interest	$ 76,620	$ 79,112	$ 95,475
Income taxes	$ 10,004	$ 29,367	$ 63,361
Non-cash financing and investing activities:			
Common stock issued to settle incentive compensation liability	–	–	$ 3,238
Liability to subsidiary minority shareholders	$ 21,362	$ 13,978	–
Issuance of stock by subsidiary for acquisition	$ 37,000	–	–

The Accompanying Notes are an Integral Part of These Statements

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Avista Corporation
For the Years Ended December 31
Dollars in thousands

	Common Stock		Accumulated Other Comprehensive Income	Retained	
	Shares	Amount	(Loss)	Earnings	Total
Balance as of December 31, 2005	48,593,139	$ 620,598	$ (23,299)	$ 171,550	$ 768,849
Net income				72,941	72,941
Equity compensation expense		3,092			3,092
Issuance of common stock through equity compensation plans	649,061	11,995		(258)	11,737
Issuance of common stock through Employee Investment Plan (401-K)	14,595	324			324
Issuance of common stock through Dividend Reinvestment Plan	95,031	2,137			2,137
Issuance of common stock	3,162,500	77,474			77,474
Other comprehensive income			9,162		9,162
Cumulative effect of accounting change (adoption of SFAS No. 158)			(3,679)		(3,679)
Cash dividends paid (common stock)				(27,927)	(27,927)
Other				415	415
Balance as of December 31, 2006	52,514,326	$ 715,620	$ (17,816)	$ 216,721	$ 914,525
Net income				38,475	38,475
Equity compensation expense		2,720			2,720
Issuance of common stock through equity compensation plans	281,224	2,559			2,559
Issuance of common stock through Employee Investment Plan (401-K)	14,685	329			329
Issuance of common stock through Dividend Reinvestment Plan	98,778	2,158			2,158
Common stock issuance costs		(69)			(69)
Other comprehensive loss			(1,792)		(1,792)
Reclassification of preferred stock issuance costs		1,334		(1,334)	–
Cash dividends paid (common stock)				(31,451)	(31,451)
Equity transactions of consolidated subsidiaries		2,282			2,282
Liability to subsidiary minority shareholders				(11,377)	(11,377)
Other				(4,393)	(4,393)
Balance as of December 31, 2007	52,909,013	$ 726,933	$ (19,608)	$ 206,641	$ 913,966
Net income				73,620	73,620
Equity compensation expense		2,600			2,600
Issuance of common stock through equity compensation plans	697,257	9,326			9,326
Issuance of common stock through Employee Investment Plan (401-K)	15,361	311			311
Issuance of common stock through Dividend Reinvestment Plan	115,943	2,328			2,328
Issuance of common stock	750,000	16,599			16,599
Other comprehensive income			13,516		13,516
Cash dividends paid (common stock)				(37,071)	(37,071)
Equity transactions of consolidated subsidiaries		16,889			16,889
Liability to subsidiary minority shareholders				(15,201)	(15,201)
Balance as of December 31, 2008	54,487,574	$ 774,986	$ (6,092)	$ 227,989	$ 996,883

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 western 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 including Avista Energy, Inc. (Avista Energy) and Advantage IQ, Inc. (Advantage IQ). Avista Energy was an electricity and natural gas marketing, trading and resource management business. On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations. See Note 3 for further information. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. See Note 30 for business segment information.

The Company's operations are exposed to risks including, but not limited to:

- global financial and economic conditions (including the availability of credit) and their effect on the Company's ability to obtain funding for working capital and long-term capital requirements on acceptable terms,
- economic conditions in the Company's service areas, including the effect on the demand for, and customers' ability to pay for, the Company's utility services,
- streamflow and weather conditions that impact hydroelectric generation, utility operations and customer demand,
- market prices and supply of wholesale energy, which the Company purchases and sells, including power, fuel and natural gas,
- regulatory disallowance of the recovery of power and natural gas costs, operating costs and capital investments and the allowance of a reasonable rate of return on investment,
- the effects of changes in legislative and governmental regulations, including restrictions on emissions from generating plants and requirements for the acquisition of new resources,
- changes in regulatory requirements,
- availability of generation facilities,
- rate increases may change customer demand for electricity and natural gas, and
- competition.

Also, like other utilities, the Company's facilities and operations are exposed to natural disasters and terrorism risks or other malicious acts. In addition, the energy business exposes the Company to the financial, liquidity, credit and price risks associated with wholesale purchases and sales of energy commodities.

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries, including variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 9).

Use of Estimates

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America 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 by the FERC.

Utility Revenues

Utility revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. 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 $84.3 million (net of $11.4 million of unbilled receivables sold) as of December 31, 2008 and $16.1 million (net of $57.2 million of unbilled receivables sold) as of December 31, 2007. See Note 6 for information related to the sale of accounts receivable. 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.

Non-Utility Energy Marketing and Trading Revenues

This category of revenues decreased significantly in 2008 and 2007 with the sale of substantially all of Avista Energy's contracts and ongoing operations on June 30, 2007. The majority of Avista Energy's contracts were accounted for under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. The net margin on derivative commodity instruments held for trading is reported as non-utility energy marketing and trading revenues. Revenues from contracts that are not derivatives under SFAS No. 133, as well as derivative commodity instruments not held for trading, are reported on a gross basis in non-utility energy marketing and trading revenues. Revenues from Canadian contracts through Avista Energy Canada, Ltd. (Avista Energy Canada), which are not held for trading, are reported on a gross basis in non-utility energy marketing and trading revenues, were $64.5 million in 2007 and $119.9 million in 2006. There were not any revenues from Avista Energy Canada in 2008.

Other Non-Utility Revenues

Service revenues from Advantage IQ are recognized in the period services are rendered. Setup fees are deferred and recognized over the term of the related customer contracts. Interest earnings on funds held for customers are an integral part of Advantage IQ's product offerings and are recognized in revenues as earned. Revenues from the other businesses are primarily derived from the operations of Advanced Manufacturing and Development and are recognized when the risk of loss transfers to the customer, which generally 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 2008, 2007 and 2006.

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 $53.9 million in 2008, $51.0 million in 2007 and $48.3 million in 2006.

Income Taxes

The Company accounts for income taxes under SFAS No. 109, "Accounting for Income Taxes." Under SFAS No. 109, a deferred 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 tax expense for the period is equal to the net change in the deferred tax asset and liability accounts from the beginning to the end of the period. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax liabilities and regulatory assets are established for tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

Other Income-Net

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

	2008	2007	2006
Interest income	$ 3,262	$ 7,812	$ 9,366
Interest on power and natural gas deferrals	3,671	4,369	6,497
Interest on income tax settlement	5,749	–	–
Equity-related Allowance for Funds Used During Construction	5,692	4,736	2,429
Net gain (loss) on investments	(1,368)	445	(512)
Other expense	(8,531)	(6,837)	(9,358)
Other income	834	281	178
Total	$ 9,309	$ 10,806	$ 8,600

Stock-Based Compensation

On January 1, 2006, the Company adopted SFAS No. 123R, which supersedes APB No. 25 and SFAS No. 123 and their related implementation guidance. The statement requires that the compensation cost relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. The Company adopted SFAS No. 123R using the modified prospective method and, accordingly, financial statement amounts for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. See Note 25 for further information.

Accumulated Other Comprehensive Loss

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

	2008	2007
Unfunded benefit obligation for pensions and other postretirement benefit plans	(6,092)	$ (12,782)
Unrealized loss on interest rate swap agreements	–	(6,826)
Total accumulated other comprehensive loss	$ (6,092)	$ (19,608)

Earnings Per Common Share

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share is calculated by dividing income available for common stock 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 24 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. See Note 8 for further information related to 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):

	2008	2007	2006
Allowance as of the beginning of the year	$ 42,582	$ 42,360	$ 44,634
Additions expensed during the year	6,595	3,148	2,895
Net deductions	(4,115)	(2,926)	(5,169)
Allowance as of the end of the year	$ 45,062	$ 42,582	$ 42,360

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):

	2008	2007
Materials and supplies	$ 19,133	$ 19,357
Fuel stock	3,673	2,214
Natural gas stored	30,720	13,414
Total	$ 53,526	$ 34,985

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 or 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. Costs of depreciable units of property retired plus costs of removal less salvage are charged to accumulated depreciation.

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. In accordance with the uniform system of accounts 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-net. The Company generally is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a fair 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 generally does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was 8.2 percent in 2008, and 9.11 percent in 2007 and 2006. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

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 2.77 percent in 2008, 2.89 percent in 2007 and 2.89 percent in 2006.

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

- electric thermal production – 32 years,
- hydroelectric production – 77 years,
- electric transmission – 49 years,
- electric distribution – 39 years, and
- natural gas distribution property – 51 years.

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 11). The Company had estimated retirement costs included as a regulatory liability on the Consolidated Balance Sheets of $213.7 million as of December 31, 2008 and $209.4 million as of December 31, 2007. These costs do not represent legal or contractual obligations.

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. Goodwill is included in other properties and investments-net on the Consolidated Balance Sheets. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2008 for the Other businesses and as of December 31, 2008 for Advantage IQ and determined that goodwill was not impaired at that time.

The changes in the carrying amount of goodwill for the year ended December 31 are as follows (dollars in thousands):

	Advantage IQ	Other	Total
Balance as of December 31, 2006	$ –	$ 6,245	$ 6,245
Goodwill removed related to sale of Avista Energy	–	(999)	(999)
Balance as of December 31, 2007	$ –	$ 5,246	$ 5,246
Goodwill acquired during the year	15,886	–	15,886
Balance as of the December 31, 2008	$ 15,886	$ 5,246	$ 21,132

The goodwill acquired in 2008 was primarily related to the Advantage IQ acquisition of Cadence Network, Inc. (Cadence Network) completed in July 2008 (see Note 5).

Other Intangibles

Other Intangibles primarily represent the amounts assigned to client relationships related to the Advantage IQ acquisition of Cadence Network (estimated amortization period of 16 years – see Note 5), software development costs (estimated amortization period of 5 to 7 years) and other. Other Intangibles are included in other properties and investments-net on the Consolidated Balance Sheets. Amortization expense related to Other Intangibles for 2008, 2007 and 2006 was $1.1 million, $0.7 million, and $0.5 million, respectively.

The gross carrying amount and accumulated amortization of Other Intangibles as of December 31, 2008 and 2007 are as follows (dollars in thousands):

	2008	2007
Client relationships	$ 8,909	$ –
Software development costs	14,067	6,811
Other	570	570
Total other intangibles	23,546	7,381
Less accumulated amortization	(5,804)	(4,500)
Total other intangibles – net	$ 17,742	$ 2,881

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

	2009	2010	2011	2012	2013
Estimated amortization expense	$ 2,424	$ 2,502	$ 2,301	$ 2,180	$ 2,246

Regulatory Deferred Charges and Credits

The Company prepares its consolidated financial statements in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." The Company prepares its financial statements in accordance with SFAS No. 71 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.

SFAS No. 71 requires the Company to reflect the impact of regulatory decisions in its financial statements. SFAS No. 71 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) are reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the statement 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 SFAS No. 71 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.

The Company's primary regulatory assets include:

- power and natural gas deferrals,
- investment in exchange power,
- regulatory asset for deferred income taxes,
- unamortized debt expense,
- assets offsetting net utility energy commodity derivative liabilities (see Note 7 for further information),
- expenditures for demand side management programs,
- expenditures for conservation programs,
- payments to the Coeur d'Alene Tribe for past water storage, and
- unfunded pensions and other postretirement benefits.

Those items without a specific line on the Consolidated Balance Sheets are included in other regulatory assets.

Regulatory liabilities include:

- utility plant retirement costs,
- natural gas deferrals, and
- liabilities offsetting net utility energy commodity derivative assets (see Note 7 for further information).

Those items without a specific line on the Consolidated Balance Sheets are included in other current liabilities and other non-current liabilities and deferred credits.

Regulatory assets that are not currently included in rate base, or earning a return (accruing interest), totaled $207.8 million as of December 31, 2008, of which the majority related to the regulatory asset for pensions and other postretirement benefits of $172.3 million, payments that will be made in 2009 and 2010 to the Coeur d'Alene Tribe for past water storage of $14.0 million, and costs incurred related to demand side management programs of $11.1 million, and asset retirement obligations of $3.3 million.

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 beginning 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, as well as premiums paid to repurchase debt. For the Company's primary 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.

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 periodically 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. Avista Utilities accrues interest on deferred power costs in the Washington jurisdiction at a rate, which is adjusted semi-annually, of 6.7 percent as of December 31, 2008.

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. Through December 31, 2008, 50 percent of the annual power supply cost variance in this range was deferred for future surcharge or rebate to customers and the Company incurs the cost of, or receives the benefit from, the remaining 50 percent. 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 incurs the cost of, or receives the benefit from, 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 (through December 31, 2008):

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%
+/- excess over $10 million	90%	10%

Effective January 1, 2009, the ERM was adjusted for the sharing level for the annual power supply cost variance in the $4.0 million to $10.0 million band. The adjustment resulted in 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. The 50 percent customers/50 percent Company sharing was maintained when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band.

The following is a summary of the revised 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 cost 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. Avista Utilities accrues interest on deferred power costs in the Idaho jurisdiction at a rate, which is adjusted annually, of 5.0 percent as of December 31, 2008.

The following table shows activity in deferred power costs for Washington and Idaho during 2006, 2007 and 2008 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2005	$ 96,191	$ 7,987	$ 104,178
Activity from January 1 – December 31, 2006:			
Power costs deferred	–	5,718	5,718
Interest and other net additions	4,291	300	4,591
Recovery of deferred power costs through retail rates	(30,323)	(4,648)	(34,971)
Deferred power costs as of December 31, 2006	70,159	9,357	79,516
Activity from January 1 – December 31, 2007:			
Power costs deferred	16,344	16,750	33,094
Interest and other net additions	3,023	788	3,811
Recovery of deferred power costs through retail rates	(31,002)	(5,732)	(36,734)
Deferred power costs as of December 31, 2007	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

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 for the prior year, 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 $18.6 million as of December 31, 2008 and net deferred natural gas costs were an asset of $2.4 million (an asset of $6.2 million and a liability of $3.8 million) as of December 31, 2007.

Reclassifications

The Company has reclassified the net decrease (increase) in funds held for customers from operating activities to investing activities and the net increase (decrease) in customer fund obligations from operating activities to financing activities in the Consolidated Statements of Cash Flows for all periods presented. The effect of the reclassifications was to decrease cash used in investing activities and increase cash used in financing activities by $0.3 million in 2007. The effect on 2006 was to increase cash used in investing activities and decrease cash used in financing activities by $51.9 million. This reclassification had no impact on the net change in cash and cash equivalents or cash flows from operating activities for any period presented.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2007, the Company adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109," (FIN 48) which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires the evaluation of a tax position as a two-step process. First, the Company is required to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the "more likely than not" recognition threshold, it is then measured and recorded at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. The adoption of FIN 48 did not have a cumulative effect on the Company's financial statements. See Note 13 for further information.

Effective January 1, 2008, the Company adopted the provisions of SFAS No. 157, "Fair Value Measurements" related to its financial assets and liabilities and nonfinancial assets and liabilities measured at fair value on a recurring basis. In February 2008, the FASB issued Staff Position No. 157-2, which deferred the effective date for certain portions of SFAS No. 157 related to nonrecurring measurements of nonfinancial assets and liabilities. The Company will be required to adopt those provisions of SFAS No. 157 in 2009. The adoption of the provisions of SFAS No. 157 that became effective on January 1, 2008, did not have a material impact on the Company's financial condition and results of operations. However, the Company expanded disclosures with respect to fair value measurements. See Note 22 for the expanded disclosures.

Effective January 1, 2008, the Company adopted SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option is elected would be reported in net income. The Company did not elect to use the fair value option under SFAS No. 159 for any financial assets and liabilities at implementation and as such the adoption of SFAS No. 159 did not have any material impact on its financial condition and results of operations.

Effective January 1, 2008 the Company adopted FASB Staff Position (FSP) FIN 39-1, "Amendment of FASB Interpretation No. 39." FSP FIN 39-1 amends certain paragraphs of FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts, an interpretation of APB Opinion No. 10 and FASB Statement No. 105." This statement permits an entity to offset fair value amounts recognized for the right to reclaim or the obligation to return cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. As of December 31, 2008 the Company did not offset any fair value cash collateral receivables against net derivative positions. As of December 31, 2007, the retrospective application of FSP FIN 39-1 had no impact on the Consolidated Balance Sheet. The fair value of cash collateral that was not offset in the Consolidated Balance Sheets as of December 31, 2008 and December 31, 2007 was $0.2 million and $12.5 million respectively.

Effective December 31, 2006, SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132 (R)" required the Company to recognize the overfunded or underfunded status of defined benefit postretirement plans in the Company's Consolidated Balance Sheet measured as the difference between the fair value of plan assets and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plans, the benefit obligation is the accumulated postretirement benefit obligation. Previously, the Company only recognized the underfunded status of defined benefit pension plans as the difference between the fair value of plan assets and the accumulated benefit obligation. 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. As such, the underfunded status of the Company's pension and other postretirement benefit plans under SFAS No. 158 resulted in the recognition as of December 31, 2006 of:

- a liability of $60.1 million (associated deferred taxes of $21.0 million) for pensions and other postretirement benefits,
- a regulatory asset of $54.2 million (associated deferred taxes of $19.0 million) for pensions and other postretirement benefits,
- an increase to accumulated other comprehensive loss of $3.7 million (net of taxes of $2.1 million), and
- the removal of the intangible pension asset of $3.7 million (was included in other deferred charges).

As such, the total effect on the deferred income tax liability for the adoption of SFAS No. 158 was a net decrease of $2.1 million. The adoption of this statement did not have any effect on the Company's net income.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations." This statement replaces SFAS No. 141 and addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. This statement 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 Company will be required to begin applying this statement to any business combinations in 2009.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements." This statement amends Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to establish accounting and reporting standards for noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. This statement 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 Company will be required to adopt SFAS No. 160 in 2009. The Company does not expect the adoption of SFAS No. 160 to have any material impact on its financial condition and results of operations. However, it will impact the presentation and disclosure of noncontrolling (minority) interests in the consolidated financial statements. As of December 31, 2008, the Company had

$11.2 million of noncontrolling (minority) interest included in other non-current liabilities and deferred credits on the Consolidated Balance Sheet. This amount will be reclassified to equity beginning in the first quarter of 2009. The Company had a reduction to net income attributable to noncontrolling (minority) interest of $1.1 million for 2008 included in other income-net on the Consolidated Statements of Income. This amount will be separately disclosed and presented in future periods. The Company is still in the process of evaluating the full impact SFAS No. 160 will have on its consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities." This statement will require disclosure of the fair value of derivative instruments and their gains and losses in a tabular format. The statement will also require disclosure of derivative features that are related to credit risk. The Company will be required to adopt SFAS No. 161 in 2009. The Company will have expanded disclosures with respect to derivatives and hedging activities.

In December 2008, the FASB issued FSP FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets". This FSP amends FASB statement No. 132(R) "Employer's Disclosures about Pensions and Other Postretirement Benefits." This statement provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. The Company will be required to adopt FSP FAS 132(R)-1 at the end of 2009. The Company will have expanded disclosures with respect to its pension and other postretirement benefit plan assets.

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. Proceeds from the transaction included cash consideration for the net assets acquired by Shell Energy and the liquidation of the remaining net current assets of Avista Energy not sold to Shell Energy (primarily receivables, restricted cash and deposits with counterparties). The pre-tax net loss on the transaction was $4.3 million, which is included in non-utility other operating expenses in the Consolidated Statements of Income for 2007.

Certain assets of Avista Energy with a net book value of approximately $30 million were not sold or liquidated. These primarily include natural gas storage and deferred tax assets. The Company expects that the natural gas storage will ultimately be transferred to Avista Utilities, subject to future regulatory approval. Avista Energy also has a power purchase agreement, related to a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant). The Lancaster Plant is owned by an unrelated third-party and all of the output from the plant is contracted to Avista Energy through 2026. The majority of the rights and obligations of the power purchase agreement were assigned to Shell Energy through the end of 2009. The Company expects that the power purchase agreement for the period 2010 through 2026 will be transferred to Avista Utilities, subject to future regulatory approval.

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 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 26), existing litigation, tax liabilities, matters with respect to natural gas storage rights, and any potential issues associated with the power purchase agreement for the Lancaster Plant. 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 with respect to claims made prior to termination.

As of February 27, 2009, neither party has made any claims under the Indemnification Agreement or Guaranty.

NOTE 4. IMPAIRMENT OF ASSETS

During the third quarter of 2007, the Company recorded an impairment charge of $2.3 million for a turbine and related equipment, which is included in other operating expenses in the Consolidated Statements of Income. The Company originally planned to use the turbine in a regulated utility generation project. At the end of the third quarter of 2007, the Company reached a conclusion to sell the turbine and related equipment, which were classified as assets held for sale as of December 31, 2007, and included in other current assets on the Consolidated Balance Sheet. The impairment charge reduced the carrying value of the assets to the estimated fair value. The turbine was sold in 2008.

Pursuant to a settlement agreement in its Washington general rate case entered into in October 2007 and approved by the WUTC in December 2007, Avista Corp. agreed to write off $3.8 million of unamortized debt repurchase costs. This expense is reflected as regulatory disallowance of unamortized debt repurchase costs in the Consolidated Statements of Income. These costs were for premiums paid to repurchase debt prior to its scheduled maturity. In accordance with regulatory accounting practices, these premiums were recorded as a regulatory asset in unamortized debt expense on the Consolidated Balance Sheet and were being amortized over the average remaining maturity of outstanding debt.

NOTE 5. ADVANTAGE IQ ACQUISITION

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 redeem their shares of Advantage IQ common stock 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. Based on the estimated fair market value of Advantage IQ common stock held by the previous owners of Cadence Network, the liability was $28.8 million as of December 31, 2008 related to this potential redemption obligation. Additionally, the minority shareholders and option holders of Advantage IQ have the right to put their shares back to Advantage IQ at their discretion. A liability of $10.4 million was outstanding as of December 31, 2008 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock (refer to Note 25 for further information).

Advantage IQ's acquisition of Cadence Network was accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed were preliminarily recorded at their respective estimated fair values as of the date of acquisition (July 2, 2008). Significant assets recorded include the following intangible assets: goodwill of $13.1 million, client relationships of $7.7 million (estimated amortization period of 16 years) and internal use software of $4.4 million (estimated amortization period of 5 to 7 years). These intangible assets are included in other property and investments on the Consolidated Balance Sheet. Final purchase accounting is pending the completion of further review of the fair market values of relevant assets and liabilities identified as of the acquisition date. The results of operations of Cadence Network are included in the consolidated financial statements beginning in the third quarter of 2008. Pro forma disclosures reflecting the effects of the acquisition of Cadence Network are not presented, as the acquisition is not material to Avista Corp.'s consolidated financial condition or results of operations.

NOTE 6. ACCOUNTS RECEIVABLE SALE

Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp. formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. On March 14, 2008, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment extended the termination date to March 13, 2009. Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. On a consolidated basis, the amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp.'s committed lines of credit (see Note 15). At each of December 31, 2008 and 2007, ARC had the ability to sell up to $85.0 million of receivables under this revolving agreement. There was $17.0 million in accounts receivable sold as of December 31, 2008 and $85.0 million in accounts receivable sold as of December 31, 2007 under this revolving agreement.

NOTE 7. ENERGY COMMODITY DERIVATIVES AND RISK MANAGEMENT

Avista Utilities is exposed to risks relating to changes in certain commodity prices. 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, both qualitative and quantitative. 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.

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 using 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 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 factors such as customer usage and weather, as well as 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 energy 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 economic, selling fuel and substituting wholesale purchases for the operation of Avista Utilities' resources, and
- other wholesale transactions to capture the value of generation and transmission resources.

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

As part of its resource optimization process described above, Avista Utilities manages the impact of fluctuations in electric energy prices by measuring and controlling the volume of energy imbalance between projected loads and resources and through the use of derivative commodity instruments for hedging purposes. 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 these energy imbalances. Management also assesses available resource decisions and actions that are appropriate for longer-term planning periods.

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 years into the future with the highest volumes hedged for the current and most immediately upcoming gas operating year (November through October). Avista Utilities also purchases a significant portion of its gas supply requirements in short-term and spot markets. Natural gas resource optimization activities include:

- wholesale market sales of surplus gas supplies,
- purchases and sales of natural gas to use under utilized pipeline capacity, and
- sales of excess natural gas storage capacity.

Avista Utilities enters into forward contracts to purchase or sell electricity and natural gas. Under these forward contracts, Avista Utilities commits to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. Certain of these forward contracts are considered derivative instruments. Avista Utilities also records derivative commodity assets and liabilities for over-the-counter and exchange-traded derivative instruments as well as certain long-term contracts.

SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recording of all derivatives as either assets or liabilities on the balance sheet measured at estimated fair value and the recognition of the unrealized gains and losses. 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.

In conjunction with the provisions of SFAS No. 133, the WUTC and the IPUC issued accounting orders authorizing Avista Utilities to offset any 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 annual adjustments to retail rates through purchased gas cost adjustments, the ERM and the PCA mechanism.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as assets or liabilities at market value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives under SFAS No. 133 are generally accounted for at cost 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.

Utility energy commodity derivatives consisted of the following as of December 31 (dollars in thousands):

	2008	2007
Current utility energy commodity derivative assets	$ 11,234	$ 12,078
Current utility energy commodity derivative liabilities	71,463	19,249
Net current regulatory asset	$ (60,229)	$ (7,171)
Non-current utility energy commodity derivative assets	$ 49,313	$ 55,313
Non-current utility energy commodity derivative liabilities	7,141	1,899
Net non-current regulatory liability	$ 42,172	$ 53,414

Non-current utility energy commodity derivative liabilities are included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets.

Market Risk

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 to the extent that nonperformance by market participants of their contractual obligations and commitments affects the supply of, or demand for, the commodity.

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 they may not be able to collect amounts owed to them. 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, and
- 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.

Credit risk also involves the exposure that counterparties perceive related to the ability of the Company 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.

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.

Other Operational and Event Risks

In addition to market and credit risk, the Company is subject to operational and event risks including, among others:

- blackouts or disruptions to distribution, transmission or transportation systems,
- forced outages at generating plants,
- fuel quality and availability,
- disruptions to information systems and other administrative resources required for normal operations, and
- weather conditions and natural disasters that can cause physical damage to property, requiring repairs to restore utility service.

Terrorism and other malicious threats are a risk to the entire utility industry. Potential disruptions to operations or destruction of facilities from terrorism or other malicious acts are not readily determinable. The Company has taken various steps to mitigate terrorism risks and prepare contingency plans in the event that its facilities are targeted.

NOTE 8. CASH DEPOSITS FROM COUNTERPARTIES

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. From time to time, margin calls are 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 $0.2 million as of December 31, 2008 and $12.5 million as of December 31, 2007. 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 9. 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 was $330.9 million and accumulated depreciation was $204.0 million as of December 31, 2008.

NOTE 10. 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):

	2008	2007
Avista Utilities:		
Electric production	$ 1,031,925	$ 1,010,997
Electric transmission	460,398	443,833
Electric distribution	958,770	881,923
Construction work-in-progress (CWIP) and other	150,292	155,317
Electric total	2,601,385	2,492,070
Natural gas underground storage	36,355	19,082
Natural gas distribution	599,596	547,153
CWIP and other	50,144	58,344
Natural gas total	686,095	624,579
Common plant (including CWIP)	133,542	115,373
Total Avista Utilities	3,421,022	3,232,022
Advantage IQ [(1)]	23,878	18,307
Other [(1)]	45,041	44,862
Total	$ 3,489,941	$ 3,295,191

(1) Included in other properties and investments-net on the Consolidated Balance Sheets.

NOTE 11. ASSET RETIREMENT OBLIGATIONS

The Company follows SFAS No. 143, "Accounting for Asset Retirement Obligations," and 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):

	2008	2007	2006
Asset retirement obligation at beginning of year	$ 3,990	$ 4,810	$ 4,529
New liability recognized	–	–	–
Liability adjustment due to revision in estimated cash flows	–	(1,063)	–
Liability settled	(29)	(71)	(51)
Accretion expense	247	314	332
Asset retirement obligation at end of year	$ 4,208	$ 3,990	$ 4,810

NOTE 12. 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 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 $28 million in cash to the pension plan in 2008 and $15 million each of 2007 and 2006. The Company expects to contribute $48 million to the pension plan in 2009.

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 $17.5 million in 2009, $18.1 million in 2010, $19.0 million in 2011, $20.0 million in 2012 and $21.2 million in 2013. For the ensuing five years (2014 through 2018), the Company expects that benefit payments under the pension plan and the SERP will total $127.0 million.

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
- reviews and approves changes to the investment and funding policies.

The Company has 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 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 investment allocation percentages by asset classes as indicated in the table in this Note.

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. The market-related value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices).

The market-related value of pension plan assets invested in real estate was determined 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 plan assets was determined as of December 31, 2008 and 2007.

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 2008, the rates at which participants are assumed to retire by age were analyzed based upon historical trends and future projections. The Company revised the rates to assume that a greater percentage of participants would retire between the ages of 55 and 65. The assumed rates were revised to range from 5 percent to 40 percent and 100 percent at age 65. The previous rates ranged from 2 percent to 30 percent and 100 percent at age 65. The change resulted in an increase of $11.0 million to the pension benefit obligation as of December 31, 2008. The change will also increase future years' pension costs.

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 employees' 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. Effective December 31, 2007, this plan was amended to eliminate a provision that allowed an executive officer to elect for their beneficiaries to receive one quarter of such payment each year over a ten-year period commencing within 30 days of the executive officer's death. The plan was also amended to provide that those who become executive officers after December 31, 2007 will no longer be eligible to receive benefits after retirement. The amendments to the plan reduced the benefit obligation by $1.6 million as of December 31, 2007.

The Company expects that benefit payments under other postretirement benefit plans will be $4.0 million in 2009, $3.8 million in 2010, $3.7 million in 2011, $3.6 million in 2012 and $3.6 million in 2013. For the ensuing five years (2014 through 2018), the Company expects that benefit payments under other postretirement benefit plans will total $16.6 million. The Company expects to contribute $4.0 million to other postretirement benefit plans in 2009, representing expected benefit payments to be paid during the year.

The Company uses a December 31 measurement date for its pension and other postretirement plans. The following table sets forth the pension and other postretirement plan disclosures as of December 31, 2008 and 2007 and the components of net periodic benefit costs for the years ended December 31, 2008, 2007 and 2006 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2008	2007	2008	2007
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 323,090	$ 315,691	$ 34,352	$ 33,632
Service cost	10,209	10,694	772	672
Interest cost	20,812	19,161	2,371	2,159
Plan amendment	–	–	–	(1,601)
Actuarial loss (gain)	17,041	(5,245)	5,611	2,612
Transfer of accrued vacation	–	–	365	585
Benefits paid	(17,580)	(16,912)	(4,518)	(3,707)
Expenses paid	–	(299)	–	–
Benefit obligation as of end of year	$ 353,572	$ 323,090	$ 38,953	$ 34,352
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 242,561	$ 225,079	$ 22,718	$ 20,878
Actual return on plan assets	(63,575)	18,799	(6,670)	1,840
Employer contributions	28,000	15,000	–	–
Benefits paid	(16,349)	(16,018)	–	–
Expenses paid	–	(299)	–	–
Fair value of plan assets as of end of year	$ 190,637	$ 242,561	$ 16,048	$ 22,718
Funded status	$ (162,935)	$ (80,529)	$ (22,905)	$ (11,634)
Unrecognized net actuarial loss	160,280	62,174	18,357	4,472
Unrecognized prior service cost	2,444	3,098	(1,452)	(1,600)
Unrecognized net transition obligation	–	–	2,021	2,526
Accrued benefit cost	(211)	(15,257)	(3,979)	(6,236)
Additional liability	(162,724)	(65,272)	(18,926)	(5,398)
Accrued benefit liability	$ (162,935)	$ (80,529)	$ (22,905)	$ (11,634)
Accumulated pension benefit obligation	$ 307,413	$ 275,159	–	–
Accumulated postretirement benefit obligation:				
For retirees			$ 18,821	$ 18,572
For fully eligible employees			$ 8,903	$ 9,675
For other participants			$ 11,229	$ 6,105

	Pension Benefits		Other Post-retirement Benefits	
	2008	2007	2008	2007
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ –	$ –	$ 1,313	$ 1,642
Unrecognized prior service cost	1,589	2,013	(943)	(1,040)
Unrecognized net actuarial loss	104,182	40,414	11,932	2,907
Total	105,771	42,427	12,302	3,509
Less regulatory asset	(98,850)	(28,560)	(13,131)	(4,594)
Accumulated other comprehensive loss (income)	$ 6,921	$ 13,867	$ (829)	$ (1,085)
Weighted-average asset allocations as of December 31:				
Equity securities	48%	49%	51%	62%
Debt securities	32%	31%	49%	38%
Real estate	6%	6%	–	–
Absolute return	11%	11%	–	–
Other	3%	3%	–	–
Target asset allocations as of December 31:				
Equity securities	39-61%	39-61%	52-72%	52-72%
Debt securities	27-33%	27-33%	28-48%	28-48%
Real estate	3-7%	3-7%	–	–
Absolute return	10-14%	10-14%	–	–
Other	0-8%	0-8%	–	–
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	6.25%	6.34%	6.25%	6.20%
Discount rate for annual expense	6.34%	6.15%	6.20%	6.15%
Expected long-term return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.72%	4.66%		
Medical cost trend pre-age 65 – initial			9.00%	9.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2017	2012
Medical cost trend post-age 65 – initial			9.00%	9.00%
Medical cost trend post-age 65 – ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2015	2011

	2008	2007	2006	2008	2007	2006
Components of net periodic benefit cost:						
Service cost	$ 10,209	$ 10,694	$ 9,963	$ 772	$ 672	$ 639
Interest cost	20,812	19,161	17,158	2,371	2,159	1,956
Expected return on plan assets	(21,138)	(19,217)	(16,997)	(1,931)	(1,775)	(1,562)
Transition obligation recognition	–	–	–	505	505	505
Amortization of prior service cost	654	653	653	(149)	–	–
Net loss recognition	3,345	2,978	3,772	575	193	90
Net periodic benefit cost	$ 13,882	$ 14,269	$ 14,549	$ 2,143	$ 1,754	$ 1,628

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, 2008 by $2.1 million and the service and interest cost by $0.2 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, 2008 by $1.8 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 $4.8 million in 2008, $5.1 million in 2007 and $4.7 million in 2006.

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. At December 31, 2008 and 2007, there were deferred compensation assets of $8.8 million and $12.1 million included in other property and investments-net and corresponding deferred compensation liabilities of $8.8 million and $12.1 million included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets.

NOTE 13. ACCOUNTING FOR INCOME TAXES

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

	2008	2007	2006
Taxes currently provided	$ 1,464	$ 31,703	$ 61,198
Deferred income taxes	44,161	(7,369)	(19,212)
Total income tax expense	$ 45,625	$ 24,334	$ 41,986

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2008, 2007 and 2006) 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):

	2008	2007	2006
Federal income taxes at statutory rates	$ 41,676	$ 21,983	$ 40,224
Increase (decrease) in tax resulting from:			
Tax effect of regulatory treatment of utility plant differences	2,260	4,526	4,342
State income tax expense	1,617	732	1,853
Preferred dividends	–	479	670
Settlement of prior year tax returns and adjustment of tax reserves	2,505	1,019	(1,437)
Manufacturing deduction	(991)	(1,738)	(735)
Kettle Falls tax credit	(1,773)	(2,645)	(3,201)
Other	331	(22)	270
Total income tax expense	$ 45,625	$ 24,334	$ 41,986

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):

	2008	2007
Deferred income tax assets:		
Allowance for doubtful accounts	$ 12,618	$ 14,791
Reserves not currently deductible	5,323	8,026
Net operating loss from subsidiary acquisition	7,262	–
Contributions in aid of construction	14,279	12,967
Deferred compensation	2,156	4,110
Unfunded benefit obligation	52,646	26,888
Utility energy commodity derivatives	42,271	25,514
Interest rate swaps	–	2,451
Tax credits	8,484	7,378
Other	16,531	17,282
Total deferred income tax assets	161,570	119,407
Deferred income tax liabilities:		
Intangible assets from subsidiary acquisition	4,337	–
Differences between book and tax basis of utility plant	447,107	413,231
Power and natural gas deferrals	13,636	29,115
Regulatory asset for pensions and other postretirement benefits	60,297	17,852
Power exchange contract	27,657	31,014
Utility energy commodity derivatives	42,271	25,514
Demand side management programs	7,693	5,943
Loss on reacquired debt	4,870	6,103
Interest rate swaps	5,251	–
Settlement with Coeur d'Alene Tribe	9,707	–
Other	9,123	11,302
Total deferred income tax liabilities	631,949	540,074
Net deferred income tax liability	$ 470,379	$ 420,667

Net current deferred income tax assets were $18.6 million as of December 31, 2008 and $20.3 million as of December 31, 2007. Net non-current deferred income tax liabilities were $488.9 million as of December 31, 2008 and $440.9 million as of December 31, 2007.

As of December 31, 2008, the Company had $8.5 million of Idaho and Oregon tax credit carryforwards. State tax credits expire from 2014 to 2020. The Company recognizes the effect of state tax credits generated from utility plant as they are utilized.

The realization of deferred 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 tax assets and determined it is more likely than not that deferred tax assets will be realized.

As disclosed in Note 2, the Company adopted FIN 48 effective January 1, 2007, which did not have a cumulative effect on the Company's financial statements.

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, Montana and California. 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 the 2004 and 2005 tax years and all issues were resolved related to these years. The IRS is currently conducting an examination of the Company's 2006 and 2007 federal income tax returns. This examination could result in a change in the liability for uncertain tax positions. 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 with respect to state income taxes could result in any adjustments that would be significant to the consolidated financial statements.

In August 2005, the Treasury Department issued regulations and the IRS issued a revenue ruling that affects the tax treatment by Avista Corp. of certain indirect overhead expenses. Avista Corp. had previously made a tax election to currently deduct certain indirect overhead costs, starting with the 2002 tax return, that were capitalized for financial accounting purposes. This election allowed Avista Corp. to take tax deductions resulting in a total reduction of approximately $40 million in current tax liabilities for 2002, 2003 and 2004. These current tax benefits were deferred on the balance sheet in accordance with the provisions of SFAS No. 109 and did not affect net income.

On the basis of the revenue ruling and related regulations, the IRS disallowed the tax deduction of indirect overhead expenses during their examination of the Company's 2001, 2002 and 2003 federal income tax returns. The Company believed that the tax deductions claimed on tax returns were appropriate based on the applicable statutes and regulations in effect at the time. Avista Corp. appealed the proposed IRS adjustment in April 2006. The Company repaid a portion of the previous tax deductions through tax payments in 2005, 2006 and 2008.

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):

	2008	2007
Balance as of the beginning of the year	$ 22,619	$ 22,619
Settlements with the IRS	(22,619)	–
Balance as of the end of the year	$ –	$ 22,619

The Company estimated that its liability for unrecognized tax benefits was $22.6 million as of December 31, 2007. In 2008, this amount was reclassified from a FIN 48 liability for unrecognized tax benefit, to a general tax liability on the Consolidated Balance Sheet. This tax liability has been reduced by the above mentioned settlement agreement to $5 million. The remaining liability is related to the indirect overhead expenses described above. The amount did not impact the 2008 tax rate, as this deferred tax adjustment was offset by an adjustment to current income taxes payable. The Company did not incur any penalties on income tax positions in 2008, 2007 or 2006. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operation expense.

The Company had net regulatory assets of $115.0 million at December 31, 2008 and $117.5 million at December 31, 2007 related to the probable recovery of certain deferred tax liabilities from customers through future rates.

NOTE 14. 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 $951.4 million in 2008, $733.5 million in 2007 and $682.5 million in 2006.

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):

	2009	2010	2011	2012	2013	Thereafter	Total
Power resources	$ 246,114	$ 127,118	$ 95,029	$ 82,093	$ 68,928	$ 390,303	$ 1,009,585
Natural gas resources	164,323	94,612	68,038	50,663	44,175	474,329	896,140
Total	$ 410,437	$ 221,730	$ 163,067	$ 132,756	$ 113,103	$ 864,632	$ 1,905,725

All of the 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 generally 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):

	2009	2010	2011	2012	2013	Thereafter	Total
Contractual obligations	$ 24,546	$ 27,805	$ 26,353	$ 29,116	$ 29,987	$ 247,381	$ 385,188

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 $14.9 million in 2008, $18.0 million in 2007 and $13.1 million in 2006.

Information as of December 31, 2008 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs (1)	Debt Service Costs (1)	Bonds Outstanding	Expiration Date
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$ 2,116	$ 1,026	$ 1,320	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,791	793	4,411	2018
Grant County PUD:						
Priest Rapids Project	3.3%	28,000	5,253	727	8,485	2055
Wanapum Project (2)	8.2%	78,000	5,715	2,663	15,143	2055
Totals		173,000	$ 14,875	$ 5,209	$ 29,359	

(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 the year 2008. Debt service costs are included in annual costs.*

(2) *The current contract expires October 31, 2009. A new contract was completed in 2001 with an expiration date of 2055. Beginning in November 2009, our rights to the output will be reduced to 3.3 percent. Under the new contract we will have the rights to the output but not the obligation to take the output. In September of each year we will be required to determine if we will take the output for the subsequent year.*

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):

	2009	2010	2011	2012	2013	Thereafter	Total
Minimum payments	$ 4,527	$ 2,967	$ 2,910	$ 2,491	$ 2,427	$ 33,698	$ 49,020

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

Avista Energy's contractual commitments to purchase energy commodities as well as commitments related to transmission, transportation and other energy-related contracts in future periods are as follows (dollars in thousands):

	2009	2010	2011	2012	2013	Thereafter	Total
Energy purchase contracts	$ 21,700	$ 26,728	$ 26,728	$ 26,530	$ 25,543	$ 290,482	$ 417,711

These contractual commitments of Avista Energy are primarily related to the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010 through 2026, the rights and obligations of the power purchase agreement for the Lancaster Plant are contracted to Avista Energy. The Company expects that these rights and obligations will be transferred to Avista Utilities, subject to future regulatory approval.

NOTE 15. SHORT-TERM BORROWINGS

The Company has 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 can request the issuance of up to $320.0 million in letters of credit. Total letters of credit outstanding were $24.3 million as of December 31, 2008 and $34.8 million as of December 31, 2007. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Additionally, the Company has a committed line of credit agreement with various banks in the total amount of $200.0 million with an expiration date of November 24, 2009. The committed line of credit is secured by $200.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreements contain customary covenants and default provisions, including a covenant requiring 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, 2008, the Company was in compliance with this covenant with a ratio of 3.27 to 1. The committed line of credit agreements also have a covenant which does 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, 2008, the Company was in compliance with this covenant with a ratio of 54.5 percent. If the proposed change in organization becomes effective, the committed line of credit agreements will remain at Avista Corp. The committed line of credit agreements also have a covenant which requires the Company to maintain a minimum funded ratio of the pension plan assets to liabilities. The Pension Protection Act of 2006 (that was implemented in 2008) modified the liability calculation utilized to calculate the funded ratio. Avista Corp. amended the covenant related to the pension funded ratio, under its $320.0 million committed line of credit agreement, to conform with the calculations under the Pension Protection Act of 2006.

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):

	2008	2007	2006
Balance outstanding at end of period	$ 250,000	$ –	$ 4,000
Maximum balance outstanding during the period	$ 250,000	$ 48,000	$ 77,000
Average balance outstanding during the period	$ 48,426	$ 6,833	$ 16,740
Average interest rate during the period	3.04%	7.91%	6.07%
Average interest rate at end of period	0.81%	– %	8.25%

Advantage IQ

In February 2008, Advantage IQ entered into a $12.5 million committed credit agreement with a bank that has an expiration date of February 2011. Advantage IQ has the ability to increase the credit facility to $25 million under the same agreement. The credit agreement is secured by substantially all of Advantage IQ's assets.

Balances outstanding and interest rates of borrowings under Advantage IQ's credit agreement were as follows as of and for the year ended December 31, 2008 (dollars in thousands):

	2008
Balance outstanding at end of period	$ 2,200
Maximum balance outstanding during the period	$ 3,000
Average balance outstanding during the period	$ 1,658
Average interest rate during the period	3.48%
Average interest rate at end of period	2.08%

NOTE 16. LONG-TERM DEBT

The following details the interest rate and maturity dates of long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2008	2007
2008	Secured Medium-Term Notes	6.06%-6.95%	$ –	$ 45,000
2010	Secured Medium-Term Notes	6.67%-8.02%	35,000	35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2013	First Mortgage Bonds (1)	7.25%	30,000	–
2018	First Mortgage Bonds (2)	5.95%	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
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)	5.00%	–	66,700
2034	Secured Pollution Control Bonds (4)	1.20%	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured long-term debt		835,000	666,700
2008	Unsecured Senior Notes	9.75%	–	272,860
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Total unsecured long-term debt		4,100	276,960
	Other long-term debt and capital leases		3,006	5,169
	Interest rate swaps		(14,129)	1,083
	Unamortized debt discount		(1,512)	(1,079)
	Total		826,465	948,833
	Current portion of long-term debt		(17,207)	(427,344)
	Total long-term debt		$ 809,258	$ 521,489

(1) *On December 16, 2008, the Company issued $30.0 million of 7.25 percent First Mortgage Bonds due in 2013. The net proceeds from the issuance of $29.9 million (net of placement agent fees and before Avista Corp.'s expenses) were used to repay $25.0 million of medium term notes that matured on December 10, 2008 and repay a portion of the borrowings outstanding under the Company's $320.0 million committed line of credit.*

(2) *On April 3, 2008, the Company issued $250.0 million of 5.95 percent First Mortgage Bonds due in 2018. The net proceeds from the issuance of $249.2 million (net of issuance discount and before Avista Corp.'s expenses), together with other available funds, were used to pay the $272.9 million of 9.75 percent Unsecured Senior Notes that matured on June 1, 2008.*

(3) *On December 31, 2008, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, Series 1999A (Avista Corporation Colstrip Project) due 2034 were remarketed. Avista Corp. purchased these Pollution Control Bonds and expects that at a later date, subject to market conditions, these bonds will be remarketed to unaffiliated investors or refunded by a new issue. Although Avista Corp. is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Consolidated Balance Sheet.*

(4) *On December 30, 2008, the City of Forsyth, Montana issued $17.0 million of its Pollution Control Revenue Refunding Bonds, Series 2008 (Avista Corporation Colstrip Project) due 2034 on behalf of Avista Corp. The proceeds of these bonds were used to refund $17.0 million of Pollution Control Revenue Refunding Bonds, Series 1999B (Avista Corporation Colstrip Project) issued by the City of Forsyth, Montana on behalf of Avista Corp. These bonds are included in the current portion of long-term debt because they are subject to purchase at any time at the option of the bond holder.*

The following table details future long-term debt maturities including long-term debt to affiliated trusts (see Note 17) (dollars in thousands):

	2009	2010	2011	2012	2013	Thereafter	Total
Debt maturities	$ 17,000	$ 35,000	$ –	$ 7,000	$ 75,000	$ 818,503	$ 952,503

Substantially all utility properties owned by the Company are subject to the lien of the Company's various mortgage indentures. 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; provided, however, that 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, 2008, property additions and retired bonds would have entitled the Company to issue $688.9 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, 2008, the net earnings test would limit the principal amount of additional bonds the Company could issue to $545.9 million.

See Note 15 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its $320.0 million and $200.0 million committed line of credit agreements.

NOTE 17. LONG-TERM DEBT TO AFFILIATED TRUSTS

In 2004, the Company issued Junior Subordinated Debt Securities, with a principal amount of $61.9 million to AVA Capital Trust III, an affiliated business trust formed by the Company. Concurrently, AVA Capital Trust III issued $60.0 million of Preferred Trust Securities to third parties and $1.9 million of Common Trust Securities to the Company. All of these securities have a fixed interest rate of 6.50 percent for five years (through March 31, 2009). Subsequent to the initial five-year fixed rate period, the securities will either have a new fixed rate or an adjustable rate. These debt securities may be redeemed by the Company on or after March 31, 2009 and will mature on April 1, 2034.

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 annual distribution rate paid during 2008 ranged from 3.06 percent to 6.00 percent. As of December 31, 2008, the annual distribution rate was 3.06 percent. 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 with respect to, the Preferred Trust Securities to the extent that AVA Capital Trust III and Avista Capital II have 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 $113.4 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 18. 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 the anticipated issuances of debt. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with changes in interest rates.

In December 2006, Avista Corp. cash settled an interest rate swap agreement and paid $3.7 million. In March 2008, the Company cash settled two interest rate swap agreements and paid a total of $16.4 million. These settlements were deferred as regulatory items (part of long-term debt) and will be amortized as a component of interest expense over the remaining ten year terms of the interest rate swap agreements (forecasted interest payments) in accordance with regulatory accounting practices.

In December 2008, the Company entered into two interest rate swaps totaling $50.0 million. Under the terms of the outstanding interest rate swap agreements as of December 31, 2008, 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 beginning in 2009. As of December 31, 2008, Avista Corp. had a current derivative asset of $0.9 million and offsetting regulatory liability 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. The interest rate swap agreements provide for mandatory cash settlement of these contracts in 2009.

In January 2009, the Company entered into two interest rate swaps totaling $50.0 million. 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 beginning in 2009. 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. The interest rate swap agreements provide for mandatory cash settlement of these contracts in 2009.

NOTE 19. 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 $4.8 million in 2008, $4.8 million in 2007 and $5.4 million in 2006.

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2008 were as follows (dollars in thousands):

	2009	2010	2011	2012	2013	Thereafter	Total
Minimum payments required	$ 4,319	$ 1,968	$ 428	$ 349	$ 346	$ 2,970	$ 10,380

NOTE 20. GUARANTEES

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount with respect to, the Preferred Trust Securities issued by its affiliates, AVA Capital Trust III and Avista Capital II, to the extent that these entities have funds available for such payments from the respective debt securities.

The output from the Lancaster Plant is contracted to Avista Energy through 2026 under a power purchase agreement. Avista Corp. has guaranteed the power purchase agreement for the performance of Avista Energy. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, the Company expects that these rights and obligations will be transferred to Avista Utilities, subject to future regulatory approval.

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 26), existing litigation, tax liabilities, matters with respect to storage rights at Jackson Prairie, and any potential issues associated with the power purchase agreement for the Lancaster Plant. 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 with respect to claims made prior to termination.

NOTE 21. 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, 2008 and 2007. In September 2007, the Company redeemed the 262,500 remaining outstanding shares of preferred stock for $26.25 million. In September 2006, the Company made a mandatory redemption of 17,500 shares of preferred stock for $1.75 million.

NOTE 22. FAIR VALUE

The carrying values of cash and cash equivalents, restricted cash, 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) 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, 2008 and 2007 (dollars in thousands):

	2008		2007	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt	$ 839,100	$ 875,451	$ 943,660	$ 969,899
Long-term debt to affiliated trusts	113,403	102,027	113,403	109,109

These estimates of fair value were primarily based on available market information.

Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swap agreements, are reported at estimated fair value on the Consolidated Balance Sheets. As disclosed in Note 2, on January 1, 2008, the Company adopted the provisions of SFAS No. 157 related to its financial assets and liabilities and nonfinancial assets and liabilities measured at fair value on a recurring basis. SFAS No. 157 establishes 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 defined by SFAS No. 157 are 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. Level 3 instruments include those that may be more structured or otherwise tailored to the Company's needs.

As required by SFAS No. 157, 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 following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Consolidated Balance Sheet as of December 31, 2008 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counter-party Netting	Total
Assets:					
Energy commodity derivatives	$ –	$ 40,104	$ 68,047	$ (47,604)	$ 60,547
Deferred compensation assets	6,990	–	–	–	6,990
Interest rate swaps	–	875	–	–	875
Total	$ 6,990	$ 40,979	$ 68,047	$ (47,604)	$ 68,412
Liabilities:					
Energy commodity derivatives	$ –	$ 110,123	$ 16,085	$ (47,604)	$ 78,604

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 our 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 and at Note 7 is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of our 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, which are also quoted under NYMEX. 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 7 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 excludes cash and cash equivalents of $1.8 million.

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

	2008
Balance as of January 1, 2008	$ 98,943
Total gains or losses (realized/unrealized)	
Included in net income	–
Included in other comprehensive income	–
Included in regulatory assets/liabilities (1)	(22,586)
Purchases, issuances, and settlements, net	(8,310)
Transfers to other categories	–
Balance as of December 31, 2008	$ 68,047

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

	2008
Balance as of January 1, 2008	$ 36,506
Total gains or losses (realized/unrealized)	
Included in net income	–
Included in other comprehensive income	–
Included in regulatory assets/liabilities (1)	(18,715)
Purchases, issuances, and settlements, net	(1,706)
Transfers to other categories	–
Balance as of December 31, 2008	$16,085

(1) In conjunction with the provisions of SFAS No. 133, the WUTC and the IPUC issued accounting orders authorizing Avista Utilities to offset any 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. As such, the Company does not recognize unrealized gains or losses on utility energy commodity derivative instruments in the Consolidated Statements of Income. The Company recognizes realized gains or losses in the period of contract settlement, subject to regulatory 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 and the PCA mechanism.

NOTE 23. COMMON STOCK

In November 1999, the Company adopted a shareholder rights plan pursuant to which holders of common stock outstanding on February 15, 1999, or issued thereafter, were granted one preferred share purchase right (Right) on each outstanding share of common stock. Each Right, initially evidenced by and traded with the shares of common stock, entitles the registered holder to purchase one one-hundredth of a share of preferred stock of the Company, without par value, at a purchase price of $70, subject to certain adjustments, regulatory approval and other specified conditions. The Rights will be exercisable only if a person or group acquires 10 percent or more of the outstanding shares of common stock or commences a tender or exchange offer, the consummation of which would result in the beneficial ownership by a person or group of 10 percent or more of the outstanding shares of common stock. Upon any such acquisition, each Right will entitle its holder to purchase, at the purchase price, that number of shares of common stock or preferred stock of the Company (or, in the case of a merger of the Company into another person or group, common stock of the acquiring person or group) that has a market value at that time equal to twice the purchase price. In no event will the Rights be exercisable by a person that has acquired 10 percent or more of the Company's common stock. The Rights may be redeemed, at a redemption price of $0.01 per Right, by the Board of Directors of the Company at any time until any person or group has acquired 10 percent or more of the common stock. In connection with the proposed statutory share exchange (see Note 28), the shareholder rights plan was amended to provide that the Rights will expire upon the earlier of the effective time of the statutory share exchange or March 31, 2009 (the originally scheduled expiration date).

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 2008, 2007 and 2006 are disclosed in the Consolidated Statements of Stockholders' Equity.

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 December 2006, the Company entered into a sales agency agreement with a sales agent, to issue up to 2 million shares of its common stock from time to time. In 2008, the Company issued 750,000 shares (total net proceeds of $16.6 million) under the sales agency agreement.

NOTE 24. EARNINGS PER COMMON SHARE

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

	2008	2007	2006
Numerator:			
Net income	$ 73,620	$ 38,475	$ 72,941
Subsidiary earnings adjustment for dilutive securities	(249)	(349)	–
Adjusted net income for computation of diluted earnings per common share	$ 73,371	$ 38,126	$ 72,941
Denominator:			
Weighted-average number of common shares outstanding-basic	53,637	52,796	49,162
Effect of dilutive securities:			
Contingent stock awards	213	168	371
Stock options	178	299	364
Weighted-average number of common shares outstanding-diluted	54,028	53,263	49,897
Total earnings per common share, basic	$ 1.37	$ 0.73	$ 1.48
Total earnings per common share, diluted	$ 1.36	$ 0.72	$ 1.46

Total stock options outstanding that were not included in the calculation of diluted earnings per common share were 250,950 for 2008, 303,950 for 2007 and 26,200 for 2006. These 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 25. 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. 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, 2008, 0.7 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, 2008, 1.7 million shares were remaining for grant under this plan.

Stock Compensation

On January 1, 2006, the Company adopted SFAS No. 123R, which supersedes APB No. 25 and SFAS No. 123 and their related implementation guidance. The statement requires that compensation cost relating to share-based payment transactions be recognized in the financial statements based on the fair value of the equity or liability instruments issued. The Company adopted SFAS No. 123R using the modified prospective method and, accordingly, financial statement amounts for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. The Company recorded stock-based compensation expense of $3.0 million for 2008, $2.7 million for 2007 and $4.0 million for 2006, which is included in other operating expenses in the Consolidated Statements of Income. The total income tax benefit recognized in the Consolidated Statements of Income was $1.1 million for 2008, $1.0 million for 2007 and $1.5 million for 2006.

Stock Options

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

	2008	2007	2006
Number of shares under stock options:			
Options outstanding at beginning of year	1,411,911	1,541,045	2,095,211
Options granted	–	–	–
Options exercised	(582,238)	(123,134)	(504,452)
Options canceled	(81,000)	(6,000)	(49,714)
Options outstanding at end of year	748,673	1,411,911	1,541,045
Options exercisable at end of year	748,673	1,411,911	1,541,045
Weighted average exercise price:			
Options granted	$ –	$ –	$ –
Options exercised	$ 13.91	$ 15.14	$ 16.12
Options canceled	$ 21.70	$ 26.59	$ 20.77
Options outstanding at end of year	$ 15.85	$ 15.38	$ 15.41
Options exercisable at end of year	$ 15.85	$ 15.38	$ 15.41
Intrinsic value of options exercised (in thousands)	$ 4,248	$ 1,022	$ 3,520
Intrinsic value of options outstanding (in thousands)	$ 2,643	$ 8,697	$ 15,256

Information for options outstanding and exercisable as of December 31, 2008 was as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17 – $12.41	393,323	$ 11.04	3.4
$15.88 – $17.31	104,400	17.19	1.1
$19.34 – $23.00	230,750	22.41	1.9
$26.59 – $28.47	20,200	27.63	1.2
Total	748,673	$ 15.85	2.6

Total cash received from the exercise of stock options was $8.1 million for 2008, $1.9 million for 2007 and $9.9 million for 2006. As of December 31, 2008 and 2007, 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, 2008 was one year.

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

	2008	2007	2006
Unvested shares at beginning of year	28,137	36,180	–
Shares granted	43,400	31,860	36,260
Shares cancelled	(1,230)	(19,936)	(80)
Shares vested	(14,368)	(19,967)	–
Unvested shares at end of year	55,939	28,137	36,180
Weighted average fair value at grant date	$ 20.05	$ 25.60	$ 21.32
Unrecognized compensation expense at end of year (in thousands)	$ 691	$ 517	$ 439
Intrinsic value, unvested shares at end of year (in thousands)	$ 1,084	$ 606	$ 916
Intrinsic value, shares vested during the year (in thousands)	$ 293	$ 461	$ –

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 (TSR) performance over a three-year period as compared against other utilities; under SFAS 123R 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. Under Statement SFAS 123R, 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 in accordance with the provisions of SFAS No. 123R. 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 costs as well as the resulting estimated fair value of performance shares granted:

	2008	2007	2006
Risk-free interest rate	2.2%	4.8%	4.6%
Expected life, in years	3	3	3
Expected volatility	20.2%	19.4%	21.9%
Dividend yield	2.8%	2.5%	2.9%
Weighted average grant date fair value (per share)	$ 16.96	$ 18.71	$ 18.08

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

The following summarizes performance share activity:

	2008	2007	2006
Opening balance of unvested performance shares	207,841	300,406	318,331
Performance shares granted	170,100	114,640	138,710
Performance shares canceled	(5,239)	(45,632)	(1,404)
Performance shares vested	(119,779)	(161,573)	(155,231)
Ending balance of unvested performance shares	252,923	207,841	300,406
Intrinsic value of unvested performance shares (in thousands)	$ 4,902	$ 4,477	$ 7,603
Unrecognized compensation expense (in thousands)	$ 2,227	$ 2,058	$ 2,400

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2008 was 1.7 years. Unrecognized compensation expense as of December 31, 2008 will be recognized during 2009 and 2010.

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

	2008	2007	2006
Performance shares vested	119,779	161,573	155,231
Impact of market condition on shares vested	21,560	(56,551)	34,151
Shares of common stock earned	141,339	105,022	189,382
Intrinsic value of common stock earned (in thousands)	$ 2,739	$ 2,262	$ 4,793

In 2008, 2007 and 2006, the number of performance shares vested was adjusted by 18 percent, (35) percent and 22 percent due to the performance condition achieved. 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 under the guidance of SFAS No. 123R. 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, 2008 and 2007, the Company had recognized compensation expense and a liability of $0.5 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 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 $1.2 million as of December 31, 2008, which will be expensed during 2009 through 2012.

In 2007, Advantage IQ amended their 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. This plan was amended to provide liquidity to participants of Advantage IQ's stock option plan. As the repurchase feature is at the discretion of the minority shareholders and option holders, a liability of $10.4 million was outstanding as of December 31, 2008 for the intrinsic value of stock options outstanding, as well as outstanding redeemable stock. As of December 31, 2007, this liability was $14.0 million. Additionally, Advantage IQ has a liability of $28.8 million 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. During 2008, $6.6 million of common stock was repurchased from Advantage IQ employees.

NOTE 26. 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. With respect to these proceedings, 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. With respect to matters that affect Avista Utilities' operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the rate making process. With respect to matters discussed in this Note that affect Avista Energy (particularly the California Refund Proceeding), any potential liabilities or refunds remain at Avista Corp. and/or its subsidiaries and were not assumed by Shell Energy and/or its affiliates.

Federal Energy Regulatory Commission Inquiry

On April 19, 2004, the FERC issued an order approving the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) reached by Avista Corp. doing business as Avista Utilities, Avista Energy and the FERC's Trial Staff with respect to an investigation into the activities of Avista Utilities and Avista Energy in western energy markets during 2000 and 2001. In the Agreement in Resolution, the FERC Trial Staff stated that its investigation found: (1) no evidence that any executives or employees of Avista Utilities or Avista Energy knowingly engaged in or facilitated any improper trading strategy; (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) that Avista Utilities and Avista Energy did not withhold relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001. In April 2005 and June 2005, the California Parties and the City of Tacoma, respectively, filed petitions for review of the FERC's decisions approving the Agreement in Resolution with the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). 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.

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 California Independent System Operator (CalISO) and the California Power Exchange (CalPX) during the period from October 2, 2000 to June 20, 2001 (Refund Period). The findings of the FERC administrative law judge were largely adopted in March 2003 by the FERC. The refunds ordered are based on the development of a mitigated market clearing price (MMCP) methodology. If the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, the FERC has held that the seller would be allowed to document these costs and limit its refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order and demonstrated an overall revenue shortfall for sales into the California spot markets during the Refund Period after the MMCP methodology is applied to its transactions. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In its February 2007 status report, the CalISO stated that it intends to process Avista Energy's cost offset filing (see further discussion regarding the California refund rerun below).

In 2001, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) defaulted on payment obligations to the CalPX and the CalISO. As a result, the CalPX and the CalISO failed to pay various energy sellers, including Avista Energy. Both PG&E and the CalPX declared bankruptcy in 2001. In March 2002, SCE paid its defaulted obligations to the CalPX. In April 2004, PG&E paid its defaulted obligations into an escrow fund in accordance with its bankruptcy reorganization. Funds held by the CalPX and in the PG&E escrow fund are not subject to release until the FERC issues an order directing such release in the California refund proceeding. As of December 31, 2008, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties.

In addition, in June 2003, the FERC issued an order to review bids above $250 per MW made by participants in the short-term energy markets operated by the CalISO and the CalPX from May 1, 2000 to October 2, 2000. In May 2004, the FERC provided notice that Avista Energy was no longer subject to this investigation. In March and April 2005, the California Parties and PG&E, respectively, petitioned for review of the FERC's decision by the Ninth Circuit. In addition, many of the other orders that the FERC has issued in the California refund proceedings are now on appeal before the Ninth Circuit. Some of those issues were consolidated as a result of a case management conference conducted in September 2004. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round is 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 Federal Power Act (FPA); (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. 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 Case. In its Order on Remand, issued in October 2007, the FERC ordered the CalISO and the CalPX to complete their refund calculations, including all entities that participated in the CalISO/CalPX markets (including those amounts that would have been paid by municipal utility entities for their sales into the CalISO and the CalPX spot markets during the refund period). The FERC then directed the CalISO to reduce refunds owed to refund recipients by the amounts attributable to municipal sales to the California markets.

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 a FPA section 309 remedy for tariff violations prior to October 2, 2000. The Ninth Circuit also granted California's petition for review challenging the FERC's exclusion of the energy exchange transactions as well as the FERC's exclusion of forward market transactions from the California refund proceedings. Petitions for rehearing were filed on November 16, 2007. It is unclear at this time what impact, if any, the Court's remand might have on Avista Energy. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit.

The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." On September 3, 2008, the CalISO filed its 42nd status report on the California recalculation process confirming that the preparatory and the FERC refund recalculations are complete (as are calculations related to fuel cost allowance offsets, emission offsets, cost-recovery offsets, and the majority of the interest calculations). The CalISO states that there are eleven (11) open issues that the FERC must rule on before any distribution can be made. Once these issues are ruled on, the CalISO states that it then intends to: (1) perform the necessary adjustment to remove refunds associated with non-jurisdictional entities and allocate that shortfall to net refund recipients; and (2) work with the parties to the various global settlements to make appropriate adjustments to the CalISO's data in order to properly reflect those adjustments.

Any potential liabilities or refunds owed by or to Avista Energy in the California Refund Proceeding were retained by Avista Corp. and/or its subsidiaries and have not been transferred to Shell Energy and/or its affiliates.

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 to the Company's management, the Company does not expect that the California refund proceeding will have a material adverse effect on its financial condition, results of operations or cash flows. This is primarily due to the fact that 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. During the hearing, Avista Corp., doing business as Avista Utilities, and Avista Energy vigorously opposed claims that rates for spot market sales were unjust and unreasonable and that the imposition of refunds would be appropriate. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. These equitable factors included the fact that the participants in the Pacific Northwest market include not only utilities and other entities that are subject to FERC jurisdiction, but also a very substantial number of governmental entities that are not subject to FERC jurisdiction with respect to wholesale sales and thus could not be ordered by the FERC to make refunds based on existing law. Seven petitions for review were filed with the Ninth Circuit challenging the merits of the FERC's decision not to order refunds and raising procedural issues.

On August 24, 2007, the Ninth Circuit issued its opinion on the consolidated petitions for review of the Pacific Northwest refund proceeding. 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 in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. Requests for rehearing were filed on December 17, 2007.

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 non-jurisdictional entities 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

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the Attorney General of the State of California (California AG) that alleged violations of the Federal Power Act 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 July 2002, the California AG requested a rehearing on the FERC order, which request was denied in September 2002. Subsequently, the California AG filed a Petition for Review of the FERC's decision with the Ninth Circuit. 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. Nonetheless, the California AG has interpreted the decision as providing authority to the FERC to order refunds in the California refund proceeding for an expanded refund period.

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 Commission'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 are 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.

Based on information currently known to the Company's management, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

State of Montana Proceedings

The Attorney General of the State of Montana (Montana AG) petitioned the Montana Public Service Commission (MPSC) to fine public utilities $1,000 a day for each day it finds they engaged in alleged "deceptive, fraudulent, anticompetitive or abusive practices" and order refunds when consumers were forced to pay more than just and reasonable rates. In February 2004, the MPSC issued an order initiating investigation of the Montana retail electricity market for the purpose of determining whether there is evidence of unlawful manipulation of that market. The Montana AG requested specific information from Avista Energy and Avista Corp. regarding their transactions within the state of Montana during the period from January 1, 2000 through December 31, 2001. In December 2008, the MPSC closed the Docket and terminated the investigation, subject to the receipt of a final report from the Montana AG.

Colstrip Generating Project Complaints

In May 2003, various parties (all of which are residents or businesses of Colstrip, Montana) filed complaints against the owners of the Colstrip Generating Project (Colstrip) in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs alleged damages to buildings as a result of foundation settlement caused by seepage from Colstrip's freshwater surge pond. Avista Corp.'s ownership interest in the freshwater surge pond is approximately 11 percent. The plaintiffs also alleged contamination and trespass damages resulting from leakage from several of Colstrip's process ponds, most of which are for Units 1 & 2 ponds of which Avista Corp. has no ownership interest. In April 2008, the owners of Colstrip reached a settlement with the plaintiffs. Under the settlement, Avista Corp.'s portion of the payment to the plaintiffs was $2.1 million. Avista Corp. may be able to recover a portion of this payment through insurance. The Company filed petitions with the WUTC and the IPUC to defer any payments as a regulatory asset, in order to allow for potential future recovery through future rates. On September 12, 2008, the IPUC issued its order approving the Company's petition. The WUTC petition was subsequently withdrawn and the portion related to the Washington jurisdiction of $1.3 million was expensed in 2008.

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of Colstrip filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. 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 and other relief similar to that asserted in the litigation described above. No trial date has been set. Because the resolution of this complaint 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.

Colstrip Royalty Claim

Western Energy Company (WECO) supplies coal to the owners of Colstrip Units 3 & 4 under a Coal Supply Agreement and a Transportation Agreement. Avista Corp. owns a 15 percent interest in Colstrip Units 3 & 4. The Minerals Management Service (MMS) of the United States Department of the Interior has issued orders, going back to 1991, to WECO to pay additional royalties concerning coal delivered to Colstrip Units 3 & 4 via the conveyor belt. The owners of Colstrip Units 3 & 4 take delivery of the coal at the beginning of the conveyor belt.

The orders assert that additional royalties are owed to MMS as a result of WECO not paying royalties in connection with revenue received by WECO from the owners of Colstrip Units 3 & 4 under the Transportation Agreement during the period October 1, 1991 through December 31, 2007.

The state of Montana also filed claims assessing additional coal production taxes on Coal Transportation Agreement revenues collected by WECO from the owners of Colstrip Units 3 & 4. Settlement of production tax claims has recently occurred between WECO and the Montana Department of Revenue.

WECO and the owners of Colstrip Units 3 & 4 have agreed to a cost sharing agreement for the payment of the settlements owed to the Montana Department of Revenue for coal production taxes and for the MMS royalty claims as they are determined through litigation or settlement. Avista Corp. estimates that its share of the royalties, taxes and interest alleged would be $2.1 million including payment for the calendar year 2008.

Based on information currently known to the Company's management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. However, the Company would most likely seek recovery, through the ratemaking process, of any amounts paid.

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). The total cost of the RI/FS is estimated to be $1.2 million and will take approximately 2 1/2 years to complete. 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 de minimus 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. As such, it is not possible to make an estimate of any liability at this time.

Lake Coeur d'Alene

In July 1998, the United States District Court for the District of Idaho issued its finding that the Tribe owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Tribe's reservation lands. This action had been brought by the United States on behalf of the Tribe against the state of Idaho. Avista Corp. was not a party to this action. The United States District Court decision was affirmed by the United States Court of Appeals for the Ninth Circuit. The United States Supreme Court affirmed this decision in June 2001. This ownership decision resulted in, among other things, Avista Corp. being liable to the Tribe for water storage on the Tribe's land and for Section 10(e) payments.

The Company's Post Falls Hydroelectric Generating Station (Post Falls), a facility constructed in 1906 with annual generation of 10 average megawatts controls the water level in the Lake for portions of the year (including portions of the lakebed owned by the Tribe). The Company has other hydroelectric generating facilities on the Spokane River downstream of Post Falls.

In December 2008, Avista Corp., the Tribe and the United States DOI finalized an agreement regarding a range of issues related to Post Falls and the Lake. The agreement establishes the amount of past and future compensation Avista Corp. will pay for the use of the Tribe's reservation lands under Section 10(e) of the Federal Power Act (Section 10(e) payments) and issues related to licensing of the Company's hydroelectric generating facilities located on the Spokane River (see Spokane River Relicensing below).

Avista Corp. agreed to compensate the Tribe a total of $39 million ($25 million paid in 2008, $10 million paid in 2009 and $4 million paid in 2010) for trespass and Section 10(e) payments for past storage of water for the period from 1907 through 2007. Avista Corp. agreed to compensate the Tribe for future storage of water through Section 10(e) payments of $0.4 million per year beginning in 2008 and continuing through the first 20 years of a new license and $0.7 million per year through the remaining term of the license.

In addition to Section 10(e) payments, Avista Corp. agreed to make annual payments over the life of a new FERC license to fund a variety of protection, mitigation and enhancement measures on the Coeur d'Alene Reservation required under Section 4(e) of the Federal Power Act. These payments involve creation of a Coeur d'Alene resource protection trust fund (the Trust Fund). Annual payments from the Company to the Trust Fund for protection, mitigation and enhancement measurements would commence with the issuance of a new FERC license and are expected to total approximately $100 million over an assumed 50-year license term.

In September 2008, as part of the settlement of the Company's general rate case the IPUC approved deferral of the Idaho jurisdictional allocation of amounts paid to the Tribe, the Trust Fund or related to the licensing of its hydroelectric generating facilities for later recovery through rates in a subsequent general rate filing. Avista Corp. included these items in its general rate case filed in January 2009. In December 2008, the WUTC approved a settlement of the Company's general rate case filing which provides similar treatment of the Washington jurisdictional allocation of amounts paid to the Tribe, the Trust Fund or related to the licensing of its hydroelectric generating facilities.

On January 27, 2009, the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) filed a Petition for Judicial Review of the WUTC's recent order approving the settlement of the Company's general rate case. Public Counsel raised a number of issues that were previously argued before the WUTC. These include whether settlement costs associated with resolving the dispute with the Tribe were prudent and whether recovery of such costs would constitute illegal "retroactive ratemaking." The appeals process may take several months and a decision is not expected until later in 2009. The court will either affirm the decision of the WUTC in its entirety or reverse the decision, in whole or in part, and remand the matter back to the WUTC for further consideration, which could possibly result in refunds.

Spokane River Relicensing

The Company owns and operates six hydroelectric plants on the Spokane River, and five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls, which have a total present capability of 144.1 MW) 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. Since the FERC was unable to issue new license orders prior to the August 1, 2007 (and subsequent August 1, 2008) expiration of the current license, an annual license was issued for all five plants, in effect extending the current license and its conditions until August 1, 2009. The Company has no reason to believe that Spokane River Project operations will be interrupted in any manner relative to the timing of the FERC's actions.

The Company filed a Notice of Intent to Relicense in July 2002. The formal consultation process involving planning and information gathering with stakeholder groups lasted through July 2005, when the Company filed its new license applications with the FERC. The Company initially requested the FERC to consider a license for Post Falls, which has a present capability of 18 MW, separately from the other four hydroelectric plants due to the complexity of issues related to the Post Falls development. In the license applications, the Company proposed a number of measures intended to address the impact of the Spokane River Project and enhance resources associated with the Spokane River. FERC licenses are granted for terms of 30 to 50 years.

Since the Company's July 2005 filing of applications to relicense the Spokane River Project, the FERC has continued various stages of processing the applications. In May 2006, the FERC issued a notice requesting other parties to provide terms and conditions regarding the two license applications. In response to that notice, a number of parties including the Tribe, the state of Idaho, Washington state agencies, and the United States DOI filed either recommended terms and conditions, pursuant to Sections 10(a) and 10(j) of the Federal Power Act (FPA), or mandatory conditions related to the Post Falls application, pursuant to Section 4(e) of the FPA. In January 2007, the FERC issued a draft Environmental Impact Statement (EIS). After review of comments, the FERC issued a final EIS in July 2007. This was the last administrative step for the FERC before the issuance of license orders; however, the FERC was unable to move forward prior to Federal Clean Water Act 401 Water Quality Certifications (Certifications) being issued by the states of Idaho and Washington.

The states of Idaho and Washington issued Certifications for the Project on June 5, 2008 and June 10, 2008, respectively. The Idaho Certification was based on a Settlement Agreement between Avista Corp., Idaho Department of Environmental Quality and the Idaho Department of Fish and Game, and is final. The Washington Certification, which was issued by the Washington Department of Ecology (Ecology); however, was appealed by Avista Corp., Inland Empire Paper and the Sierra Club/Center for Environmental Law and Policy. All issues, with the exception of one appealed by the Sierra Club/Center for Environmental Law and Policy (aesthetic spills at the Upper Falls plant) were resolved through a four-party Settlement Agreement. Avista Corp. is continuing negotiations on the remaining issue. A hearing is scheduled before the Washington Pollution Control Hearing Board in August 2009 to address the remaining issue under appeal.

On December 16, 2008 Avista, the United States DOI, and the Tribe reached agreement resolving Federal Power Act Section 4(e) conditions, as well as the payment of annual charges under Section 10(e) of the FPA regarding Post Falls, which stores water on a portion of the Coeur d'Alene Indian Reservation. The three parties submitted a request to the FERC on January 29, 2009 to incorporate the agreed-upon terms and conditions in a new single 50-year license for all five Spokane River hydroelectric plants.

The United States Department of Fish and Wildlife concurred, via a letter to FERC on July 31, 2008, that the Spokane River Project is not likely to adversely affect any listed or threatened endangered species.

Avista Corp. can not determine exactly when the FERC will complete action on the applications. Once granted, a new license will describe the final conditions Avista Corp. will be responsible to implement, and the term for a new license.

The Company's estimate of the potential cost of the conditions proposed for the Spokane River Project, based on estimates of what it would cost to implement the recommendations and conditions included in the FERC's FEIS and the numerous Settlement Agreements, total approximately $305 million over a 50-year period.

In addition, the December 16, 2008 settlement agreement between the Company and the Tribe resolved FPA Section 10(e), or storage payments related to the Post Falls hydroelectric facility. Under the Agreement, Avista Corp. will pay the Tribe $0.4 million annually for the first 20 years of a new FERC license and $0.7 million annually for the remainder of the license term for section 10(e) charges.

The WUTC approved, for future recovery, costs incurred in relicensing the Spokane River project, as well as the costs related to settlement with the Tribe. The WUTC approved deferred accounting treatment, with a carrying cost, until these costs are reflected in future retail rates. The IPUC approved similar deferred accounting treatment. Our general rate cases, filed in January 2009, reflect recovery of both the direct and deferred costs. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to the relicensing of the Spokane river plants.

Clark Fork Settlement Agreement

Dissolved atmospheric gas levels exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement, the Company developed an abatement and mitigation strategy with the other signatories to the agreement and developed the Gas Supersaturation Control Program (GSCP). The Idaho Department of Environmental Quality and the USFWS approved the GSCP in February 2004 and the FERC issued an order approving the GSCP in January 2005.

The GSCP provides for the opening and modification of one and, potentially, both of the two existing diversion tunnels built when Cabinet Gorge was originally constructed. When river flows exceed the capacity of the powerhouse turbines, the excess flows would be diverted to the tunnels rather than released over the spillway. The Company has undertaken physical and computer modeling studies to confirm the feasibility and likely effectiveness of the tunnel solution. Analysis of the predicted total dissolved gas performance indicates that the tunnels will not meet the performance criteria anticipated in the GSCP. In August 2007, the Gas Supersaturation Subcommittee concluded that the tunnel project does not meet the expectations of the GSCP and is not an acceptable project. As a result, the Company has met and will continue meeting with key stakeholders to review and amend the GSCP which includes developing alternatives to the construction of the tunnels. The Company has expended $5.0 million on the tunnel project. The WUTC and IPUC have accepted the recovery of these costs through rates.

The USFWS has listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to 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.

Air Quality

The Company must be in compliance with requirements under the Clean Air Act and Clean Air Act Amendments for its thermal generating plants. The Company continues to monitor legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide and carbon dioxide, as well as other greenhouse gas and 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 put in place 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.

Compliance with new and proposed requirements and possible additional legislation or regulations will result in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities. The Company, along with the other owners of Colstrip, completed the first phase of testing on two mercury control technologies. The joint owners of Colstrip were encouraged by preliminary results and believe that we will be able to comply with the Montana law without utilizing the temporary alternate emission limit provision. Preliminary estimates indicate that the Company's share of installation capital costs will be $1.5 million and annual operating costs will increase by $2.9 million (beginning in late-2009). The Company will continue to seek recovery, through the ratemaking process, of the costs to comply with various air quality requirements.

Residential Exchange Program

The residential exchange program is intended to provide access to the benefits of low-cost federal hydroelectricity to residential and small-farm customers of the region's private (investor owned) and public (governmental or customer owned) utilities. The Bonneville Power Administration (BPA) administers the residential exchange program under the Northwest Power Act. Previously, Avista Corp. and other private utilities in the Pacific Northwest executed settlement agreements with BPA to resolve each party's rights and obligations under the residential exchange program. These settlements covered payment of benefits for the period October 1, 2001, through September 30, 2011. On May 3, 2007, the Ninth Circuit ruled that the BPA exceeded its authority when it entered into the settlement agreements with private utilities (including Avista Corp.) for the period from 2001 through 2011.

In February 2008, the BPA initiated its WP-07 Supplemental rate case (WP-07S) to, among other things, determine the level of benefits for customers served by private utilities (including Avista Corp.) for its fiscal year 2009. In addition to resolving residential exchange issues for the long-term, the BPA also proposed an interim payout to private utilities for its fiscal year 2008, which included $9.6 million for customers of Avista Corp. Rate adjustments to pass through the interim payment to Avista Corp.'s customers were approved by the WUTC and IPUC in April 2008. In September 2008, the BPA issued its final Record of Decision in WP-07S. Avista Corp. is evaluating the BPA's final Record of Decision, and may take steps to challenge the BPA's final Record of Decision. Avista Corp. has executed new Residential Exchange contracts with the BPA, for customer benefits in 2009. Rate adjustments to pass through the payments in the amount of $2.4 million for the period November 1, 2008 through October 31, 2009 have been approved by the WUTC and IPUC.

Since the residential exchange settlement payments are passed through to Avista Corp.'s customers as adjustments to electric bills, there is no effect on Avista Corp.'s net income or cash flows.

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 in-depth 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 have and have not agreed to a settlement and 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.

The Company has potential liabilities under the Federal Endangered Species Act for species of fish that have either already been added to the endangered species list, been listed as "threatened" or been petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company.

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 potentially adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The Company is participating in this extensive adjudication process, which is unlikely to be concluded in the foreseeable future.

As of December 31, 2008, the Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represented approximately 50 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 expires in March 2010. Two local agreements in Oregon, which cover approximately 50 employees, expire in April 2010.

NOTE 27. AVISTA UTILITIES REGULATORY MATTERS

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	January 2009	8.22%	10.2%	46%
Idaho electric and natural gas	October 2008	8.45%	10.2%	48%
Oregon natural gas	April 2008	8.21%	10.0%	50%

Washington General Rate Cases

As approved by the WUTC, on January 1, 2008, electric rates for the Company's Washington customers increased by an average of 9.4 percent, which was designed to increase annual revenues by $30.2 million. As part of this general rate increase, the base level of power supply costs used in the ERM calculations was updated. Also, on January 1, 2008, natural gas rates increased by an average of 1.7 percent, which was designed to increase annual revenues by $3.3 million.

In September 2008, the Company entered into a settlement stipulation with respect to its general rate case that was filed with the WUTC in March 2008. Other parties to the settlement stipulation are the staff of the WUTC, Northwest Industrial Gas Users, and the Energy Project. The Industrial Customers of Northwest Utilities (ICNU) joined in portions of the settlement and the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) did not join in the settlement stipulation. 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 is 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 is designed to increase annual revenues by $4.8 million.

On January 27, 2009, Public Counsel filed a Petition for Judicial Review of the WUTC's recent order approving the Company's multiparty settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These include whether settlement costs associated with resolving the dispute with the Coeur d'Alene Tribe were prudent and whether recovery of such costs would constitute illegal "retroactive ratemaking." Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony by the Company to update its filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses.

The appeal itself does not prevent the new rates from going into effect. The appeals process may take several months and a decision is not expected until later in 2009. The court will either affirm the decision of the WUTC in its entirety or reverse the decision, in whole or in part, and remand the matter back to the WUTC for further consideration, which could possibly result in refunds.

In January 2009, the Company filed a general rate case with the WUTC requesting to increase base electric rates for the Company's Washington customers. In the general rate case filing, the Company requested a net electric rate increase of 8.6 percent. The net electric rate increase is based on a requested 16.0 percent increase in billed rates with an offsetting 7.4 percent reduction in the current ERM surcharge. The Company also requested a 2.4 percent increase in natural gas rates. The filing is designed to increase annual base electric service revenues by $69.8 million ($37.5 million net after considering the reduction in the current ERM surcharge) and increase annual natural gas service revenues by $4.9 million. The Company's request is based on a proposed rate of return on rate base of 8.68 percent, with a common equity ratio of 47.5 percent and an 11.0 percent return on equity. The WUTC generally has up to 11 months to review a general rate case filing.

As part of the general rate case settlement agreement that was modified and approved by the WUTC in December 2005, the Company agreed to increase the utility equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008. The utility equity component met this target as it was approximately 47.6 percent as of December 31, 2008.

Idaho General Rate Cases

In August 2008, the Company entered into an all-party settlement stipulation with respect to 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 is 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 is designed to increase annual revenues by $3.9 million.

In January 2009, the Company filed a general rate case with the IPUC requesting to increase base electric rates for its Idaho customers. In the general rate case filing, the Company requested a net electric rate increase of 7.8 percent. The net electric rate increase is based on a requested 12.8 percent increase in billed rates with an offsetting 5.0 percent reduction in the current PCA surcharge. The Company also requested a 3.0 percent increase in natural gas rates. The filing is designed to increase annual base electric service revenues by $31.2 million ($18.9 million net after considering the reduction in the current PCA surcharge) and increase annual natural gas service revenues by $2.7 million. The Company's request is based on a proposed rate of return on rate base of 8.8 percent, with a common equity ratio of 50 percent and an 11.0 percent return on equity. The IPUC generally has up to seven months to review a general rate case filing.

Oregon General Rate Case

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).

NOTE 28. POTENTIAL HOLDING COMPANY FORMATION

At the Annual Meeting of Shareholders in May 2006, the shareholders of Avista Corp. approved a proposal to proceed with a statutory share exchange, which would change the Company's organization to a holding company structure. The holding company, currently named AVA Formation Corp. (AVA), would become the parent of Avista Corp. After the contemplated dividend to AVA of the capital stock of Avista Capital (Avista Capital Dividend) now held by Avista Corp., AVA would then also be the parent of Avista Capital. The Avista Capital Dividend would effect the structural separation of Avista Corp.'s non-utility businesses from its regulated utility business.

Avista Corp. received approval from the FERC in April 2006 (conditioned on approval by the state regulatory agencies), the IPUC in June 2006 and the WUTC in February 2007. Avista Corp. also filed for approval from the utility regulators in Oregon and Montana and proceedings are pending in each of these jurisdictions. The statutory share exchange is subject to the receipt of the remaining regulatory approvals and the satisfaction of other conditions. The Company cannot predict when the remaining regulatory approvals will be obtained or if they will be on terms acceptable to the Company.

The IPUC accepted a stipulation entered into between Avista Corp. and the IPUC Staff that sets forth a variety of conditions, which would serve to segregate the Company's utility operations from the other businesses conducted by the holding company. The stipulation among other things would require Avista Corp. to maintain certain common equity levels as part of its capital structure. Avista Corp. committed to increase its actual utility common equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008, which is consistent with provisions of the Company's Washington general rate case implemented on January 1, 2006. The calculation of the utility equity component is essentially the ratio of Avista Corp.'s total common equity to total capitalization excluding, in each case, Avista Corp.'s investment in Avista Capital. The utility equity component was approximately 47.6 percent as of December 31, 2008. In addition, IPUC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 25 percent of total capitalization which, for this purpose, includes long and short-term debt, capitalized lease obligations and preferred and common equity.

The WUTC accepted a similar stipulation entered into between Avista Corp. and the WUTC staff. WUTC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 30 percent of total capitalization.

Pursuant to the Plan of Share Exchange, a statutory share exchange would be effected whereby each outstanding share of Avista Corp. common stock would be exchanged for one share of AVA common stock, no par value, so that holders of Avista Corp. common stock would become holders of AVA common stock and Avista Corp. would become a subsidiary of AVA. The other outstanding securities of Avista Corp. would not be affected by the statutory share exchange, with limited exceptions for stock options and other securities outstanding under equity compensation and employee benefit plans.

NOTE 29. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2013. Total payments under these contracts were $15.4 million in 2008, $15.4 million in 2007 and $12.5 million in 2006. 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 $15.1 million in 2009, $15.4 million in 2010, $14.5 million in 2011, $14.5 million in 2012 and $14.9 million in 2013. 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.

NOTE 30. 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 other investments and operations of various subsidiaries as well as certain other operations of Avista Capital.

In prior periods, the Company had a reportable Energy Marketing and Resource Management segment. The activities of this business segment were conducted primarily by 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, as well as to certain other subsidiaries of Shell Energy. Completion of this transaction effectively ended the majority of the operations of this segment. The remaining activities do not represent a reportable business segment in 2008 and are included in the Other category for segment reporting purposes. The historical activities were reclassified to the Other category in accordance with the provisions of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." See Note 3 for further information.

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, 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)	70,032	6,090	(2,502)	3,588	–	73,620
Capital expenditures	219,239	3,485	175	3,660	–	222,899
For the year ended December 31, 2007:						
Operating revenues	$ 1,288,363	$ 47,255	$ 82,139	$ 129,394	$ –	$ 1,417,757
Resource costs	780,998	–	68,676	68,676	–	849,674
Other operating expenses	198,778	33,841	33,942	67,783	–	266,561
Depreciation and amortization	86,091	2,402	2,157	4,559	–	90,650
Income (loss) from operations	150,053	11,012	(22,636)	(11,624)	–	138,429
Interest expense [2]	86,389	194	811	1,005	(954)	86,440
Income taxes	26,663	3,942	(6,271)	(2,329)	–	24,334
Net income (loss)	43,822	6,651	(11,998)	(5,347)	–	38,475
Capital expenditures	205,811	2,323	957	3,280	–	209,091
For the year ended December 31, 2006:						
Operating revenues	$ 1,267,938	$ 39,636	$ 198,737	$ 238,373	$ –	$ 1,506,311
Resource costs	751,646	–	144,137	144,137	–	895,783
Other operating expenses	187,457	27,069	39,477	66,546	–	254,003
Depreciation and amortization	81,904	2,088	3,091	5,179	–	87,083
Income from operations	177,049	10,479	12,032	22,511	–	199,560
Interest expense [2]	95,521	609	1,968	2,577	(1,931)	96,167
Income taxes	33,127	3,616	5,243	8,859	–	41,986
Net income	57,794	6,255	8,892	15,147	–	72,941
Capital expenditures	161,266	2,627	1,192	3,819	–	165,085
Total Assets:						
As of December 31, 2008	$ 3,434,844	$ 125,911	$ 69,992	$ 195,903	–	$ 3,630,747
As of December 31, 2007	3,009,499	108,929	71,369	180,298	–	3,189,797

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

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

NOTE 31. 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 2008 and 2007 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2008				
Operating revenues	$ 496,307	$ 350,310	$ 382,685	$ 447,461
Operating expenses	437,246	293,820	357,353	403,433
Income from operations	$ 59,061	$ 56,490	$ 25,332	$ 44,028
Net income	$ 25,231	$ 23,545	$ 7,359	$ 17,485
Outstanding common stock:				
Weighted average, basic	53,020	53,301	53,773	54,445
End of period	53,049	53,496	54,422	54,488
Total earnings per common share, diluted	$ 0.47	$ 0.44	$ 0.13	$ 0.32
Dividends paid per common share	$ 0.165	$ 0.165	$ 0.18	$ 0.18
Trading price range per common share:				
High	$ 21.39	$ 22.10	$ 23.30	$ 22.06
Low	$ 18.09	$ 19.86	$ 20.72	$ 16.58
2007				
Operating revenues	$ 459,187	$ 304,005	$ 267,662	$ 386,903
Operating expenses	420,250	263,787	251,926	343,365
Income from operations	$ 38,937	$ 40,218	$ 15,736	$ 43,538
Net income (loss)	$ 14,094	$ 14,183	$ (3,875)	$ 14,073
Outstanding common stock:				
Weighted average, basic	52,684	52,775	52,834	52,877
End of period	52,737	52,826	52,859	52,909
Total earnings (loss) per common share, diluted	$ 0.26	$ 0.26	$ (0.07)	$ 0.26
Dividends paid per common share	$ 0.145	$ 0.15	$ 0.15	$ 0.15
Trading price range per common share:				
High	$ 25.81	$ 24.89	$ 22.38	$ 22.24
Low	$ 22.91	$ 21.17	$ 18.19	$ 19.58

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, 2008.

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, 2008 is effective.

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, 2008.

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, 2008, 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, 2008, 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, 2008 of the Company and our report dated February 27, 2009 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 27, 2009

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 7, 2009.

Executive Officers of the Registrant Name	Age	Business Experience
Scott L. Morris	51	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 staff and management positions with the Company since 1981.
Malyn K. Malquist	56	Executive Vice President since September 2008 (announced he will retire effective March 31, 2009); Executive Vice President and Chief Financial Officer May 2006 – September 2008; Senior Vice President and Chief Financial Officer January 2006 – May 2006; Senior Vice President, Chief Financial Officer and Treasurer February 2004 – January 2006; Senior Vice President and Chief Financial Officer November 2002 – February 2004; Senior Vice President September 2002 – November 2002; prior to employment with the Company: General Manager of Truckee Meadows Water Authority June 2001 – September 2002; President of Malyn Malquist Consulting January 2001 – June 2001; Chief Executive Officer of Data Engines, Inc. June 2000 – October 2000; Various positions at Sierra Pacific Resources April 1994 – April 2000, positions included Chairman of the Board, Chief Executive Officer, President, Senior Vice President, Chief Financial Officer and Principal Operations Officer.
Mark T. Thies	45	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	55	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	53	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.
Christy M. Burmeister-Smith	52	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 staff and management positions with the Company since 1980.

James M. Kensok	50	Vice President and Chief Information Officer since January 2007; Chief Information Officer February 2001 – December 2006; various other staff and management positions with the Company since 1996.
Don F. Kopczynski	53	Vice President since May 2004; Vice President of Transmission and Distribution Operations – Avista Utilities since May 2004; various other staff and management positions with the Company and its subsidiaries since 1979.
David J. Meyer	55	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	50	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 staff and management positions with the Company since 1981.
Richard L. Storro	58	Vice President since January 2009; Vice President Energy Resources – Avista Utilities since January 2009. Various other staff and management positions with the Company since 1973.
Dennis P. Vermillion	47	Vice President since July 2007; 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 staff and management positions with the Company since 1985.
Ann M. Wilson	43	Vice President of Finance and Treasurer since February 2008; Vice President and Treasurer May 2007 – February 2008; Vice President and Controller January 2006 – May 2007; Vice President and Controller of Avista Energy January 2000 – January 2006; various other staff and management positions with the Company since 1997.
Roger D. Woodworth	52	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 staff and management positions with the Company since 1979.

All of the Company's executive officers, with the exception of James M. Kensok, Don F. Kopczynski and Kelly O. Norwood, were officers or directors of one or more of the Company's subsidiaries in 2008. 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 controller), 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 7, 2009.

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 7, 2009.

(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 7, 2009.

(c) Changes in control:

None.

(d) Securities authorized for issuance under equity compensation plans as of December 31, 2008:

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)	462,850	$ 15.74	746,813
Equity compensation plans not approved by security holders (3)	285,823	$ 16.02	1,705,177
Total	748,673	$ 15.85	2,451,990

(1) Excludes unvested restricted shares and performance share awards granted under Avista Corp.'s Long Term Incentive Plan. At December 31, 2008, 55,939 Restricted Share awards were outstanding. Performance share awards may be paid out at zero shares at a minimum achievement level; 252,923 shares at target level; or 379,385 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 7, 2009.

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 7, 2009.

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, 2008, 2007 and 2006

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2008, 2007 and 2006

Consolidated Balance Sheets as of December 31, 2008 and 2007

Consolidated Statements of Cash Flows for the Years Ended December 31, 2008, 2007 and 2006

Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2008, 2007 and 2006

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules:

None

(a) 3. Exhibits:

Reference is made to the Exhibit Index commencing on page 118. 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).

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 27, 2009	By /s/ Scott L. Morris
Date	Scott L. Morris 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 Scott L. Morris (Chairman of the Board, President and Chief Executive Officer)	Principal Executive Officer	February 27, 2009
/s/ Mark T. Thies Mark T. Thies (Senior Vice President and Chief Financial Officer)	Principal Financial Officer	February 27, 2009
/s/ Christy M. Burmeister-Smith Christy M. Burmeister-Smith (Vice President, Controller and Principal Accounting Officer)	Principal Accounting Officer	February 27, 2009
/s/ Erik J. Anderson Erik J. Anderson	Director	February 27, 2009
/s/ Kristianne Blake Kristianne Blake	Director	February 27, 2009
/s/ Brian W. Dunham Brian W. Dunham	Director	February 27, 2009
/s/ Roy L. Eiguren Roy L. Eiguren	Director	February 27, 2009
/s/ Jack W. Gustavel Jack W. Gustavel	Director	February 27, 2009
/s/ John F. Kelly John F. Kelly	Director	February 27, 2009
/s/ Michael L. Noël Michael L. Noël	Director	February 27, 2009
/s/ Heidi B. Stanley Heidi B. Stanley	Director	February 27, 2009
/s/ R. John Taylor R. John Taylor	Director	February 27, 2009

	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.
4.23	2-94816	4(a)-23	Twenty-Second Supplemental Indenture, dated as of March 1, 1984.

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
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.
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.

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
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 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.
4.48	333-82165	4(a)	Indenture dated as of April 1, 1998 between Avista Corporation and The Bank of New York, as Successor Trustee.
4.49	1-3701 (with March 31, 2004 10-Q)	4(a)	Indenture dated as of April 1, 2004 between Avista Corporation and Union Bank of California, N.A., as Trustee.
4.50	1-3701 (with March 31, 2004 10-Q)	4(b)	Avista Corporation Officer's Certificate (Under Section 301 of the Indenture, dated as of April 1, 2004).
4.51	1-3701 (with March 31, 2004 10-Q)	4(c)	AVA Capital Trust III Amended and Restated Declaration of Trust, dated as of April 5, 2004, among Avista Corporation, Union Bank of California, N.A., as Institutional Trustee, SunTrust Delaware Trust Company, as Delaware Trustee, and Malyn K. Malquist and Diane C. Thoren, as Regular Trustees.
4.52	1-3701 (with Form 8-K dated as of May 12, 2005)	4.2	First Supplemental Loan Agreement between City of Forsyth, Montana, and Avista Corporation, dated as of May 1, 2005, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.53	1-3701 (with Form 8-K dated as of May 12, 2005)	4.3	First Supplemental Trust Indenture between City of Forsyth, Montana, and J.P. Morgan Trust Company, N.A. (successor in interest to Chase Manhattan Bank and Trust Company, National Association) as Trustee, dated as of May 1, 2005, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
4.54	1-3701 (with Form 8-K dated as of May 12, 2005)	4.6	Loan Agreement, Restated as of May 1, 2005, between City of Forsyth, Montana and Avista Corporation, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.55	1-3701 (with Form 8-K dated as of May 12, 2005)	4.7	Trust Indenture, Restated as of May 1, 2005, between City of Forsyth, Montana and J. P. Morgan Trust Company, N.A. (successor in interest to Chase Manhattan Bank and Trust Company, N.A.) as Trustee, relating to $66,700,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 1999A.
4.56	1-3701 (with Form 8-K dated as of December 30, 2008)	4.1	Loan Agreement between City of Forsyth, Montana, and Avista Corporation, dated as of December 1, 2008 relating to $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2008.
4.57	1-3701 (with Form 8-K dated as of December 30, 2008)	4.2	Trust Indenture between City of Forsyth, Montana, and Bank of New York Mellon Trust Company, N.A. as Trustee, dated as of December 1, 2008, relating to $17,000,000 City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2008.
4.58	1-3701 (with Form 8-K dated November 15, 1999)	4	Rights Agreement, dated as of November 15, 1999, between the Company and the Bank of New York as successor Rights Agent.
4.59	1-3701 (with June 30 Form 10-Q)	4.1	Amendment No. 1 to the Rights Agreement, dated as of March 1, 2006.
10.1	1-3701 (with Form 8-K dated as of December 15, 2004)	10.1	Credit Agreement, dated as of December 17, 2004 among Avista Corporation, the Banks listed therein, Bank of America, N.A., as Managing Agent, Keybank National Association and U.S. Bank, National Association, as Documentation Agents, Wells Fargo Bank, as Documentation Agent and an Issuing Bank, Union Bank of California, N.A., as Syndication Agent and an Issuing Bank, and The Bank of New York, as Administrative Agent and an Issuing Bank.
10.2	1-3701 (with Form 8-K dated as of April 6, 2006)	10.1	Amendment No. 1, dated as of April 6, 2006, to and under the Credit Agreement, dated as of December 17, 2004, among Avista Corporation, the Banks party thereto, Bank of America, N.A., as Managing Agent, Keybank National Association and U.S. Bank, National Association, as Documentation Agents, Wells Fargo Bank, as Documentation Agent and an Issuing Bank, Union Bank of California, N.A., as Syndication Agent and an Issuing Bank, and The Bank of New York, as Administrative Agent and an Issuing Bank.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
10.3	[2]	10.1	Amendment No. 2, dated as of December 19, 2008, to and under the Credit Agreement, dated as of December 17, 2004, among Avista Corporation, the Banks party thereto, Bank of America, N.A., as Managing Agent, Keybank National Association and U.S. Bank, National Association, as Documentation Agents, Wells Fargo Bank, as Documentation Agent and an Issuing Bank, Union Bank of California, N.A., as Syndication Agent and an Issuing Bank, and The Bank of New York Mellon f/k/a The Bank of New York, as Administrative Agent and an Issuing Bank.
10.4	1-3701 (with Form 8-K dated as of December 15, 2004)	10.2	Bond Delivery Agreement, dated as of December 17, 2004, between Avista Corporation and The Bank of New York.
10.5	1-3701 (with June 30, 2002 Form 10-Q)	4(e)	Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corp., as Seller, Avista Corporation, as initial Servicer and Eaglefunding Capital Corporation, as Conduit Purchaser and Fleet National Bank, as Committed Purchaser and Fleet Securities, Inc. as Administrator.
10.6	1-3701 (with 2004 Form 10-K)	4(d)-1	Amendment No. 1 to Receivables Purchase Agreement.
10.7	1-3701 (with 2004 Form 10-K)	4(d)-2	Amendment No. 2 to Receivables Purchase Agreement.
10.8	1-3701 (with Form 8-K dated March 22, 2005)	10.1	Amendment No. 3, dated as of March 22, 2005, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Adminstrator.
10.9	1-3701 (with Form 8-K dated March 20, 2006)	10.1	Amendment No. 4, dated as of March 20, 2006, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Adminstrator.
10.10	1-3701 (with March 31, 2006 Form 10-Q)	10.1	Amendment No. 5, dated as of May 4, 2006, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.
10.11	1-3701 (with Form 8-K dated March 19, 2007)	10.1	Amendment No. 6, dated as of March 19, 2007, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.

Exhibit	Previously Filed [1] With Registration Number	As Exhibit	
10.12	1-3701 (with Form 8-K dated March 14, 2008)	10.1	Amendment No. 7, dated as of March 14, 2008, to the Receivables Purchase Agreement, dated as of May 29, 2002, among Avista Receivables Corporation, as Seller, Avista Corporation, as Servicer and Ranger Funding Company, LLC (formerly known as Receivables Capital Company LLC), as Conduit Purchaser and Bank of America, N.A., as Committed Purchaser and as Administrator.
10.13	1-3701 (with Form 8-K dated as of November 26, 2008)	10.1	Credit Agreement, dated as of November 26, 2008 among Avista Corporation, the Banks listed therein, JPMorgan Chase Bank, N.A., as Documentation Agent, Wells Fargo Bank, National Association as Syndication Agent, and Union Bank of California, N.A., as Administrative Agent.
10.14	1-3701 (with Form 8-K dated as of December 30, 2008)	10.1	Letter of Credit and Reimbursement Agreement, dated as of December 1, 2008, between Avista Corporation and Bank of America, N.A., relating to $17,000,000 Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) Series 2008.
10.15	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.
10.16	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.
10.17	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).
10.18	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).
10.19	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).
10.20	2-60728	5(e)	Power Sales Contract (Wanapum Project) with Public Utility District No. 2 of Grant County, Washington, dated as of June 22, 1959 (effective until November 1, 2009).
10.21	2-60728	5(e)-1	First Amendment to Power Sales Contract (Wanapum Project) with Public Utility District No. 2 of Grant County, Washington, dated as of December 19, 1977 (effective until November 1, 2009).
10.22	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.

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
10.23	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.
10.24	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.
10.25	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.
10.26	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.
10.27	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.
10.28	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.
10.29	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.
10.30	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.
10.31	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.
10.32	1-3701 (with June 30, 2007 Form 10-Q)	10.3	Security Agreement dated as of June 30, 2007 given by Avista Capital, Inc. in favor of Coral Energy Holding, L.P. and certain of its affiliates.
10.33	[2]		Executive Deferral Plan of the Company. [3][5]
10.34	[2]		The Company's Unfunded Supplemental Executive Retirement Plan. [3][5]
10.35	1-3701 (with 1992 Form 10-K)	10(t)-11	The Company's Unfunded Supplemental Executive Disability Plan. [3]
10.36	1-3701 (with 2007 Form 10-K)	10.34	Income Continuation Plan of the Company. [3]
10.37	1-3701 (with 2006 Form 10-K)	10.37	Avista Corporation Long-Term Incentive Plan. [3]
10.38	1-3701 (with 2004 Form 10-K)	10(o)-6	Avista Corp. Performance Award Plan Summary. [3]

	Previously Filed [1]		
Exhibit	With Registration Number	As Exhibit	
10.39	1-3701 (with 2004 Form 10-K)	10(o)-7	Avista Corporation Performance Award Agreement. [3]
10.40	1-3701 (with 2002 Form 10-K)	10(q)-8	Employment Agreement between the Company and Malyn K. Malquist. [3]
10.41	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]
10.42	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]
10.43	333-47290	99.1	Non-Officer Employee Long-Term Incentive Plan.
10.44	[2]		Form of Change of Control Agreement between the Company and its Executive Officers. [3][5][6]
10.45	[2]		Form of Change of Control Agreement between the Company and its Executive Officers. [3][5][7]
10.46	1-3701 (with September 30, 2007 Form 10-Q)	10.1	Avista Corporation Non-Employee Director Compensation.
12	[2]		Statement re computation of ratio of earnings to fixed charges and preferred dividend requirements.
21	[2]		Subsidiaries of Registrant.
23	[2]		Consent of Independent Registered Public Accounting Firm.
31.1	[2]		Certification of Chief Executive Officer.
31.2	[2]		Certification of Chief Financial Officer.
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).

(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) *The plans were modified to comply with Section 409A of the Internal Revenue Code. No significant changes were made to the plans.*
(6) *Applies for Christy M. Burmeister-Smith, Don F. Kopczynski, James M. Kensok, David J. Meyer, Kelly O. Norwood, Richard L. Storro, Dennis P. Vermillion, Ann M. Wilson and Roger D. Woodworth.*
(7) *Applies for Marian M. Durkin, Karen S. Feltes, Malyn K. Malquist, Scott L. Morris, and Mark T. Thies.*

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

	Years Ended December 31				
	2008	2007	2006	2005	2004
Fixed charges, as defined:					
Interest charges	$ 74,914	$ 80,095	$ 88,426	$ 84,952	$ 84,746
Amortization of debt expense and premium – net	4,673	6,345	7,741	7,762	8,301
Interest portion of rentals	1,601	1,612	1,802	2,394	2,443
Total fixed charges	$ 81,188	$ 88,052	$ 97,969	$ 95,108	$ 95,490
Earnings, as defined:					
Income from continuing operations	$ 73,620	$ 38,475	$ 72,941	$ 44,988	$ 35,614
Add (deduct):					
Income tax expense	45,625	24,334	41,986	25,764	21,592
Capitalized interest	(4,612)	(3,864)	(2,934)	(1,689)	(1,393)
Total fixed charges above	81,188	88,052	97,969	95,108	95,490
Total earnings	$ 195,821	$ 146,997	$ 209,962	$ 164,171	$ 151,303
Ratio of earnings to fixed charges	2.41	1.67	2.14	1.73	1.58

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 Power, LLC	Washington
Avista Turbine Power, Inc.	Washington
AVA Formation Corp.	Washington
Avista Ventures, Inc.	Washington
Pentzer Corporation	Washington
Bay Area Manufacturing, Inc.	Washington
Advanced Manufacturing and Development, Inc.	California
Avista Receivables Corporation	Washington
Avista Capital II	Delaware
AVA Capital Trust III	Delaware
Spokane Energy, LLC	Delaware
Steam Plant Square, LLC	Washington
Courtyard Office Center, LLC	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, 033-32148, 333-33790, 333-47290, and 333-126577 on Form S-8; in Registration Statement Nos. 333-106491, 033-53655, 333-39551, 333-82165, 333-63243, 333-16353, 333-16353-01, 333-16353-02, 333-16353-03, 333-64652, 033-60136, 333-10040, 333-113501, 333-139239, and 333-155657 on Form S-3; in Registration Statement No. 333-61599 on Form S-4; and in AVA Formation Corp.'s Registration Statement No. 333-131872 on Form S-4 of our report dated February 27, 2009, relating to the consolidated financial statements of Avista Corporation and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph for certain changes in accounting and presentation resulting from the impact of recently adopted accounting standards), and our report dated February 27, 2009, relating to the effectiveness of Avista Corporation 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, 2008.

/s/ Deloitte & Touche LLP

Seattle, Washington
February 27, 2009

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 27, 2009

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

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 27, 2009

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

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, 2008 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 27, 2009

/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

	2008	2007	2006	2005	2004	1998
Financial Results						
Operating revenues	$ 1,676,763	$ 1,417,757	$ 1,506,311	$ 1,359,607	$ 1,151,580	$ 1,330,637
Operating expenses	1,491,852	1,279,328	1,306,751	1,211,953	1,011,110	1,157,604
Gain on sale of utility properties	–	–	–	4,093	–	–
Income from operations	184,911	138,429	199,560	151,747	140,470	173,033
Interest expense	79,587	86,440	96,167	92,714	93,047	69,017
Income taxes	45,625	24,334	41,986	25,764	21,592	43,430
Income from continuing operations	73,620	38,475	72,941	44,988	35,614	78,316
Loss from discontinued operations	–	–	–	–	–	(177)
Net income before cumulative effect of accounting change	73,620	38,475	72,941	44,988	35,614	78,139
Cumulative effect of accounting change	–	–	–	–	(460)	–
Net income	73,620	38,475	72,941	44,988	35,154	78,139
Preferred stock dividend requirements (1)	–	–	–	–	–	8,399
Income available for common stock	$ 73,620	$ 38,475	$ 72,941	$ 44,988	$ 35,154	$ 69,740
Earnings per common share, diluted:						
Earnings from continuing operations	$ 1.36	$ 0.72	$ 1.46	$ 0.92	$ 0.73	$ 1.28
Loss from discontinued operations	–	–	–	–	–	–
Earnings before cumulative effect of accounting change	1.36	0.72	1.46	0.92	0.73	1.28
Cumulative effect of accounting change	–	–	–	–	(0.01)	–
Total earnings per common share, diluted	$ 1.36	$ 0.72	$ 1.46	$ 0.92	$ 0.72	$ 1.28
Total earnings per common share, basic	$ 1.37	$ 0.73	$ 1.48	$ 0.93	$ 0.73	$ 1.28
Common Stock Statistics						
Dividends paid per common share	$ 0.690	$ 0.595	$ 0.570	$ 0.545	$ 0.515	$ 1.05
Book value per common share	$ 18.30	$ 17.27	$ 17.41	$ 15.82	$ 15.50	$ 12.07
Shares of common stock:						
Outstanding at year-end	54,488	52,909	52,514	48,593	48,472	40,454
Average – basic	53,637	52,796	49,162	48,523	48,400	54,604
Average – diluted	54,028	52,263	49,897	48,979	48,886	54,658
Return on average common equity:						
Total company	7.7%	4.2%	8.7%	5.9%	4.7%	11.3%
Utility only	8.0%	5.8%	9.6%	10.2%	6.6%	12.7%
Non-utility only	4.9%	-3.4%	6.2%	-3.0%	1.0%	9.1%
Common stock price:						
High	$ 23.30	$ 25.81	$ 27.52	$ 20.20	$ 19.17	$ 24.88
Low	$ 16.58	$ 18.19	$ 17.61	$ 16.31	$ 15.51	$ 16.25
Year-end close	$ 19.38	$ 21.54	$ 25.31	$ 17.71	$ 17.67	$ 19.25

Avista Corporation
As of and for the years ended December 31
Dollars in thousands, except per share data and ratios

	2008	2007	2006	2005	2004	1998
Debt and Preferred Stock Statistics						
Pretax interest coverage:						
Including AFUDC/AFUCE	2.45(x)	1.75(x)	2.11(x)	1.84(x)	1.60(x)	2.72(x)
Excluding AFUDC/AFUCE	2.32(x)	1.65(x)	2.06(x)	1.80(x)	1.56(x)	2.67(x)
Embedded cost of long-term debt	6.69%	7.84%	7.79%	8.09%	8.27%	7.62%
Embedded cost of preferred stock	– %	– %	7.39%	7.39%	7.39%	7.21%
Credit Ratings (Standard & Poor's/Moody's)						
Senior secured debt	BBB+/Baa2	BBB+/Baa2	BBB-/Baa3	BBB-/Baa3	BBB-/Baa3	A/A3
Senior unsecured debt	BBB-/Baa3	BBB-/Baa3	BB+/Ba1	BB+/Ba1	BB+/Ba1	A-/Baa1
Preferred stock	BB/Ba2	BB/Ba2	BB-/Ba3	BB-/Ba3	BB-/Ba3	A-/Baa1
Financial Condition						
Total assets	$ 3,630,747	$ 3,189,797	$ 4,056,508	$ 4,948,494	$ 3,711,621	$ 3,253,636
Total net utility property	2,492,191	2,351,342	2,215,037	2,126,417	1,956,063	1,470,942
Utility property capital expenditures (excluding equity AFUDC)	219,239	205,811	161,266	215,341	116,739	92,295
Long-term debt (including current portion)	826,465	948,833	976,459	1,029,514	986,988	730,022
Long-term debt to affiliated trusts	113,403	113,403	113,403	113,403	113,403	110,000
Preferred stock subject to mandatory redemption (1)	–	–	26,250	28,000	29,750	35,000
Convertible Preferred Stock	–	–	–	–	–	269,227
Stockholders' equity	$ 996,883	$ 913,966	$ 914,525	$ 768,849	$ 751,106	$ 488,034

(1) Preferred stock was reclassified from equity to liabilities in 2003 with the adoption of SFAS No. 150. 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

	2008	2007	2006	2005	2004	1998
Avista Utilities						
Electric Operations						
Electric operating revenues (millions of dollars):						
Residential	$ 279.6	$ 251.4	$ 234.7	$ 211.9	$ 209.5	$ 157.0
Commercial	247.7	224.2	221.2	203.5	201.8	149.8
Industrial	101.8	95.2	92.9	91.6	90.3	64.6
Public street and highway lighting	6.0	5.5	5.3	4.9	4.8	3.4
Total retail revenues	635.1	576.3	554.1	511.9	506.4	374.8
Wholesale revenues	141.8	105.7	126.2	151.4	62.4	457.3
Revenues from sales of fuel	44.7	12.9	48.2	41.8	64.0	–
Other revenues	16.9	16.2	18.9	18.0	19.3	24.0
Total electric operating revenues	$ 838.5	$ 711.1	$ 747.4	$ 723.1	$ 652.1	$ 856.1
Electric energy sales (millions of kWhs):						
Residential	3,744	3,670	3,578	3,420	3,343	3,217
Commercial	3,188	3,132	3,110	2,994	2,919	2,810
Industrial	2,059	2,084	2,062	2,091	2,076	1,878
Public street and highway lighting	26	26	25	25	25	24
Total retail energy sales	9,017	8,912	8,775	8,530	8,363	7,929
Wholesale energy sales	1,964	1,594	2,117	2,508	1,472	19,215
Total electric energy sales	10,981	10,506	10,892	11,038	9,835	27,144
Retail electric customers (average per year):						
Residential	311,381	306,737	300,940	294,036	288,422	265,891
Commercial	39,075	38,488	37,912	37,282	36,728	34,407
Industrial	1,388	1,378	1,388	1,408	1,416	1,169
Public street and highway lighting	434	426	425	421	418	383
Total retail electric customers	352,278	347,029	340,665	333,147	326,984	301,850

Avista Corporation
As of and for the years ended December 31

	2008	2007	2006	2005	2004	1998
Electric Operations (continued)						
Retail electric customers (at year-end):						
Residential	313,660	310,701	305,293	298,961	292,150	269,101
Commercial	39,173	39,001	38,362	37,587	37,040	34,708
Industrial	1,384	1,383	1,378	1,393	1,416	1,003
Public street and highway lighting	440	427	417	428	408	399
Total retail electric customers	354,657	351,512	345,450	338,369	331,014	305,211
Revenue per residential kWh (cents)	7.47	6.85	6.56	6.20	6.27	4.88
Use per residential customer (kWh)	12,023	11,965	11,888	11,630	11,591	12,099
Revenue per commercial kWh (cents)	7.77	7.16	7.11	6.80	6.91	5.33
Use per commercial customer (kWh)	81,583	81,377	82,028	80,314	79,465	81,676
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	3,851	3,689	4,128	3,611	3,789	3,860
Thermal generation (from Company facilities)	3,693	3,640	3,434	3,666	2,408	3,522
Purchased power – long-term hydro contracts	833	861	787	864	794	910
Purchased power – wholesale	3,253	2,959	3,101	3,519	3,422	19,405
Power exchanges	(17)	(18)	35	10	38	26
Total power resources	11,613	11,131	11,485	11,670	10,451	27,723
Energy losses and company use	(632)	(625)	(593)	(632)	(616)	(579)
Total electric energy resources	10,981	10,506	10,892	11,038	9,835	27,144
Total resources available at peak (MW):						
Company owned:						
Hydro	765	617	980	980	965	956
Thermal	724	830	837	836	532	705
Purchased power:						
Long-term hydro contracts	132	171	143	70	167	192
Other	859	684	658	670	888	3,138
Total resources available at peak (winter)	2,480	2,302	2,618	2,556	2,552	4,991
Net system peak demand (winter)	1,821	1,685	1,656	1,660	1,766	1,701
Wholesale obligations	562	367	431	282	454	3,064
Total requirements (winter)	2,383	2,052	2,087	1,942	2,220	4,765
Reserve margin	4%	11%	20%	24%	13%	5%
Annual load factor	62%	61%	59%	56%	62%	64%

Avista Corporation
As of and for the years ended December 31

	2008	2007	2006	2005	2004	1998
Natural Gas Operations						
Natural gas operating revenues (millions of dollars):						
Residential	$ 276.4	$ 264.5	$ 257.8	$ 229.7	$ 194.5	$ 92.6
Commercial	152.1	148.4	146.6	126.6	104.7	49.6
Industrial and interruptible	12.2	11.3	11.7	11.9	9.4	5.3
Total retail revenues	440.7	424.2	416.1	368.2	308.6	147.5
Wholesale revenues	281.7	142.2	93.2	58.1	0.2	24.8
Transportation revenues	6.3	6.6	6.5	7.6	8.1	12.1
Other revenues	5.5	4.2	4.8	4.3	3.6	8.7
Total natural gas operating revenues	$ 734.2	$ 577.2	$ 520.6	$ 438.2	$ 320.5	$ 193.1
Natural gas therms delivered (millions of therms):						
Residential	210.1	195.7	192.8	199.4	201.7	187.6
Commercial	128.2	121.6	121.0	123.0	122.8	122.3
Industrial and interruptible	12.2	10.8	11.0	13.5	13.3	17.5
Total retail	350.5	328.1	324.8	335.9	337.8	327.4
Wholesale	345.9	223.1	154.9	72.9	0.3	0.0
Transportation and other	149.3	149.2	150.2	153.5	157.5	385.3
Total natural gas therms delivered	845.7	700.4	629.9	562.3	495.6	712.7
Retail natural gas customers (average per year):						
Residential	277,892	273,415	267,345	265,294	268,571	226,165
Commercial	32,901	32,327	31,746	31,652	31,886	28,236
Industrial and interruptible	297	302	295	307	311	336
Total retail natural gas customers	311,090	306,044	299,386	297,253	300,768	254,737
Retail natural gas customers (at year-end):						
Residential	280,687	277,397	272,109	265,502	272,871	233,017
Commercial	33,123	32,840	32,173	31,476	31,675	28,770
Industrial and interruptible	292	298	304	299	304	332
Total retail natural gas customers	314,102	310,535	304,586	297,277	304,850	262,119

Avista Corporation
As of and for the years ended December 31

	2008	2007	2006	2005	2004	1998
Natural Gas Operations (continued)						
Revenue per residential therm (in dollars)	1.32	1.35	1.34	1.15	0.96	0.49
Use per residential customer (therms)	756	716	721	752	751	829
Revenue per commercial therm (in dollars)	1.19	1.22	1.21	1.03	0.85	0.41
Use per commercial customer (therms)	3,897	3,760	3,811	3,885	3,853	4,330
Heating degree days (at Spokane, Washington):						
Actual	7,052	6,539	6,332	6,538	6,314	5,951
30 year average	6,820	6,820	6,820	6,820	6,820	6,842
Actual as a percent of average	103%	96%	93%	96%	93%	87%
Advantage IQ						
Revenues (millions of dollars)	$ 59.1	$ 47.3	$ 39.6	$ 31.7	$ 23.4	$ 1.3
Total assets (millions of dollars)	$ 125.9	$ 108.9	$ 100.4	$ 46.1	$ 47.3	$ 2.5
Other						
Revenues (millions of dollars)	$ 45.0	$ 82.1	$ 198.7	$ 185.9	$ 292.7	$ 2,640.2
Total assets (millions of dollars)	$ 70.0	$ 71.4	$ 1,060.2	$ 2,064.3	$ 1,056.1	$ 1,241.2

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 at Avista's Web site. The address is 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 358015
Pittsburgh, PA 15252-8015
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 7, 2009, 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 in advance of the annual meeting and to listen to the live webcast. The webcast will be archived at www.avistacorp.com for one year to allow shareholders to listen to it at their convenience.

Exchange Listing
Ticker Symbol: AVA
New York Stock Exchange

Certifications
On June 2, 2008, 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 2008, 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 2008. Our 2008 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.

Special thanks to these talented companies and their employees of the great Inland Northwest for their help with this year's annual report — Klündt | Hosmer; J. Craig Sweat Photography; Brian Prechtel Photography; Ross Printing; and Avista Corp. Investor Relations, Finance and Corporate Communications.

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.

In our commitment to green thinking, this year's annual report is printed on paper made from responsibly managed forests.

AVISTA Corp.

1411 East Mission Avenue
Spokane, Washington 99202
509.489.0500
www.avistacorp.com