2007 Annual Report

sound leadership | *reliable energy*

AVISTA Corp.

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company profile

Avista generates, transmits and distributes energy, while providing innovative energy solutions to our residential, commercial and industrial customers. Through two lines of business, Avista Utilities and Advantage IQ, we constantly strive to create value for our customers, investors, communities and employees. **Avista Utilities** delivers dependable energy to 352,000 electricity and 311,000 natural gas customers in three Western states. **Advantage IQ,** with a portfolio of specially designed e-tools and services, helps multi-site companies manage telecom, utility and waste-related expenses.

CABINET GORGE PENSTOCK
This annual report cover showcases Avista's infrastructure investment. By beginning with sound leadership and a dedicated effort to serve the overall interests of our investors, customers, employees and communities, Avista sets the course for a sustainable and prosperous future.

leadership

Scott L. Morris
Chairman, President & Chief Executive Officer

Dear Fellow Shareholders:

Successful leadership is more than sitting in the corner office. It's more than having great ideas, and it's more than driving the bottom line. Leadership at Avista Corp. is balancing the interests of investors, customers, employees and communities. Serving these stakeholders well is the heart of our success. This is not a fad for us; it's the mark of our company. We do what we say we will do, and you'll hear our actions speaking louder than our words. As I take on the additional roles of chairman and chief executive officer, I am honored to carry on our company's tradition of leadership – in service, innovation and commitment.

We are well-positioned to meet the increasingly complex challenges in the energy and utility sector thanks to the hard work of our employees and the guidance of Gary Ely, who retired as chairman of the board and chief executive officer at the end of 2007. Gary led our company from the depths of the

Ensuring the reliability of our infrastructure brings value to our shareholders.

Western energy crisis through the rebuilding of confidence and financial health. Now, some seven years later, Avista has regained its investment grade credit rating and strengthened relationships with investors, customers and regulators.

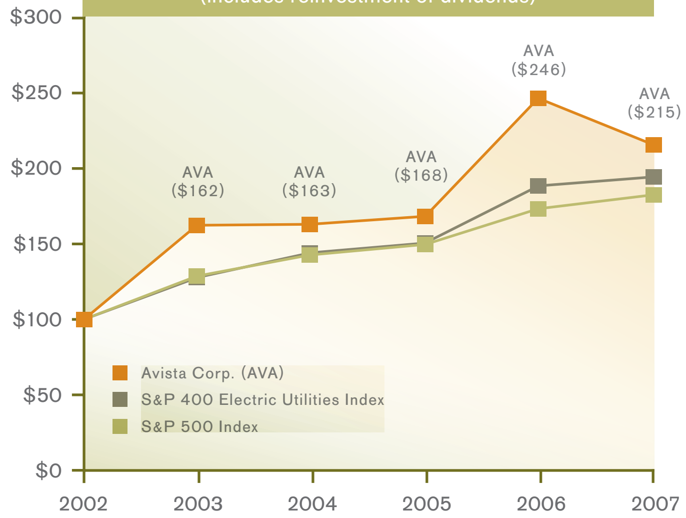
There have been good years for Avista and there have been challenging years. 2007 was a challenging year. We were disappointed in the company's financial performance, following a strong showing in 2006. This wasn't totally unexpected, as our request for an abbreviated rate filing with the Washington Utilities and Transportation Commission was refused late in 2006. This delayed the recovery of power supply and transmission costs. So, with costs higher than what were allowed in rates, our 2007 results were negatively impacted. In addition, two tough quarters at Avista Energy – formerly our energy marketing and resource management subsidiary – compounded the impact on the bottom line. The sale of substantially all of Avista Energy's contracts and ongoing operations to Shell Energy North America (U.S.), L.P. last June will help improve the stability of our earnings going forward. While this business performed profitably overall for the corporation since its formation in 1997, its business was a source of risk, requiring a larger balance sheet than ours to effectively compete in the marketplace.

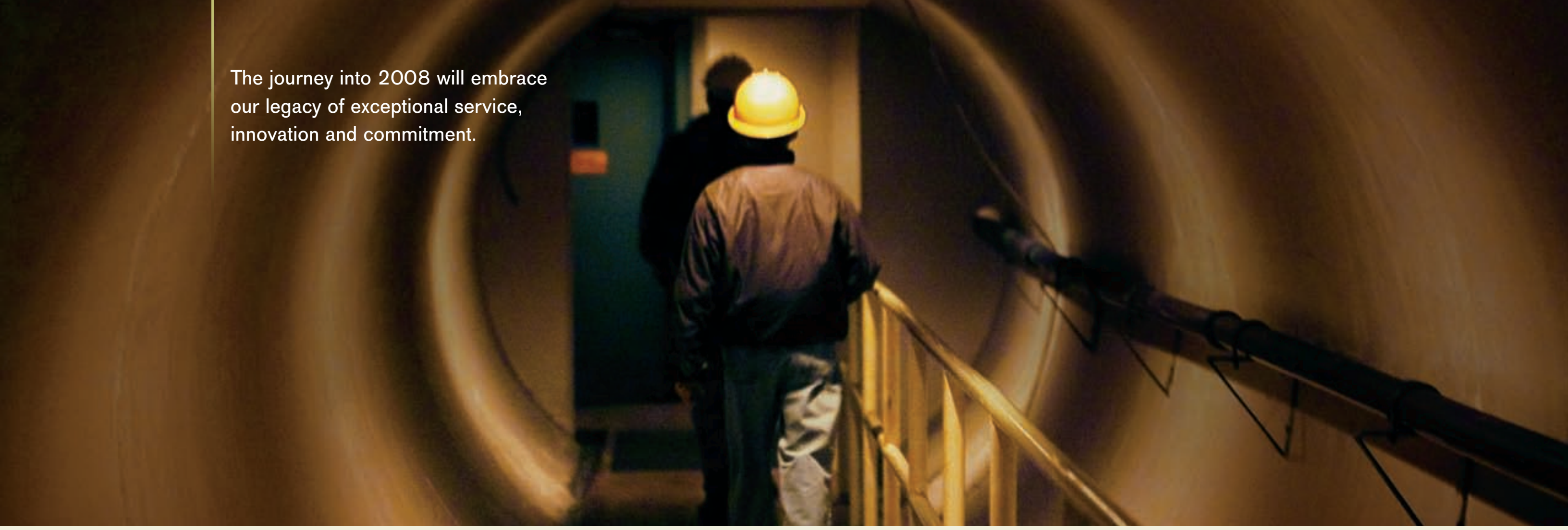
We know that investing in the reliability of our infrastructure and earning the allowed rates of return on those investments are the cornerstones to bringing value to our shareholders and an important part of our strategic goals. It's much like investing in rebuilding our nation's roads and bridges – vital to moving forward. We're working diligently with state regulators to attain rate relief for the significant capital expenditures we've made – and will continue to make – in transmission infrastructure, upgrades to renewable hydropower facilities and recovery of power supply costs. And we will review the need for these kinds of rate adjustments on an annual basis to help us stay on track in gaining reasonable returns on our investments and to signal the true cost of energy to our customers.

Maximizing shareholder value at Advantage IQ, our non-utility subsidiary, is also a key strategic goal for the years ahead. This business, which is at the forefront of its industry, continues to grow its customer base, as well as sustain annual increases in net income. We are pleased with its performance and look forward to further developing this valuable asset.

We are all in the midst of a worldwide discussion, and no matter which side of it you are on, it's inevitable that it will affect you. I am speaking, of course, about climate change. While others are just now coming to the table with "green" achievements, we are proud that they are common practice for Avista and have been since our founding. In fact, according to the 2006 Natural

TOTAL RETURN TO SHAREHOLDERS
(includes reinvestment of dividends)





Resources Defense Council Benchmarking Air Emissions study, only eight other major utilities have a smaller carbon footprint than Avista. We intend to keep it that way. When it comes to addressing renewable energy and climate change issues, we're leading the way. We have joined the Chicago Climate Exchange to stay in the forefront of carbon management. And our 20-year integrated resource plan calls for an increased emphasis on renewable resources and energy efficiency.

We are actively participating in the regional and federal processes that will shape new laws and regulations to ensure that there is proper recognition of our significant existing renewable resource base – our hydro and biomass projects – when new greenhouse gas emissions rules are created. And we're partnering with others who will push the boundaries of applied research and innovative technology to improve performance and responsibly develop resources as energy demand continues to grow. It's the right thing to do.

Helping our customers reap the benefits of energy efficiency is an important part of what we are doing. We have a long history of offering direct and practical ways in which "every little bit" of energy efficiency can make a difference for us all. As we partner with customers to manage their energy choices, we keep in mind that the most cost-effective new generating resource is the one we don't have to build, thanks to energy-saving efforts.

Every day, in all kinds of weather, our employees are doing what they do best – reliably serving our customers. I'm humbled by the dedication the men and women of Avista bring to their work. As we're seeing in companies across the nation, there's a shift beginning in our workforce from Baby Boomers to Generation X-ers, and the Millennials are fast approaching. We are being purposeful in our approaches to the shifting work styles and lifestyles these employees bring to the company. And we're implementing succession plans for work force development and the timely transfer of knowledge.

Unfortunately in our line of work, tragedies sometimes occur. We lost Avista Line Foreman Bob Smith in a tragic accident in 2007. He was doing what he loved most, helping at a local school event. His untimely death deeply touched all of us and brought home again the reasons we pursue safety as a value at Avista. More than anything else I want each of our employees to return home safely each and every day. That's why we spend a great deal of time on safety education for our family of employees.

We have been and will remain integral partners in the communities we serve. This is a commitment we take very seriously. Our corporate philanthropy, employees' civic involvement and individual volunteer work are at the core of Avista's efforts to enhance the health and vitality of the cities and towns where we live and work. This is the culture of Avista.

As we begin our journey together, I want to thank you for your continued interest in Avista Corp. Our employees and I truly appreciate your investment in our company. And while change is inevitable, one thing remains very clear: the people who make Avista what it is today, and what it will be tomorrow, are dedicated to their work and to all those we serve. You can count on us to operate the company in a manner consistent with our legacy of exceptional service, innovation and commitment.

Scott L. Morris
Chairman, President & Chief Executive Officer

More than 50 percent of Avista's energy generation comes from clean, renewable resources such as the Spokane River.

resources

Avista is located in one of the most livable regions of this country, something that we've known for years, but others are just now discovering. The Pacific Northwest is grounded in its scenic beauty, its bountiful agriculture, a favorable business climate and a long history of innovation. Such a diversified economy is rich in opportunities for the people and companies in this area. Avista is no exception. That's why we work side-by-side with the communities we serve, helping to build the infrastructure, steward the natural resources and sustain the economic health of the region.

Partnering with Avista to incorporate energy efficiencies, the new Silver LEED Certified Spokane Convention Center has helped to increase tourism and economic development in the Inland Northwest.

This is one of the faster growing regions of the United States, with populations in some locales within Avista's service territory increasing by up to 3 percent a year, compared to a national average of 1 percent. Along with the growing number of households, businesses and recreation opportunities comes an increasing demand for energy.

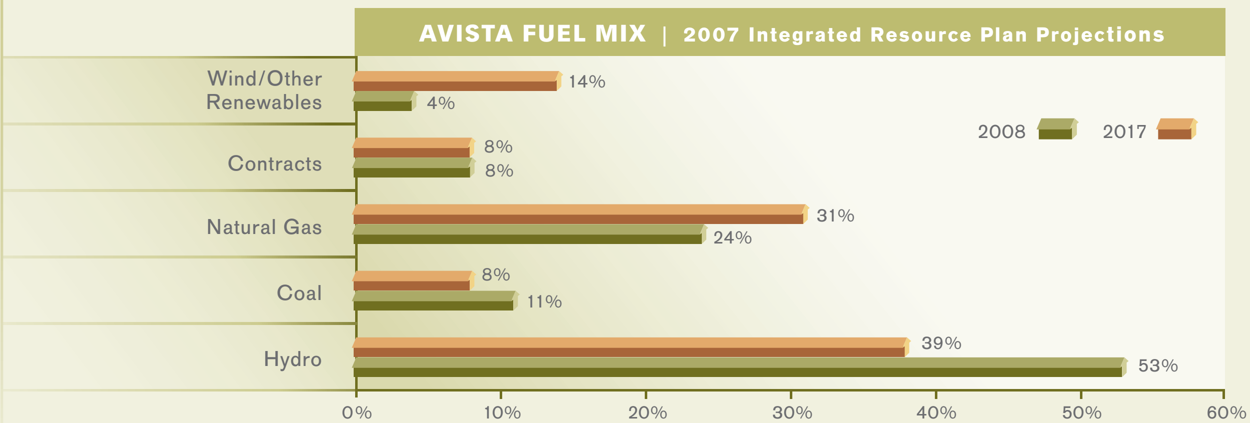
AVISTA CORP. SERVICE TERRITORY

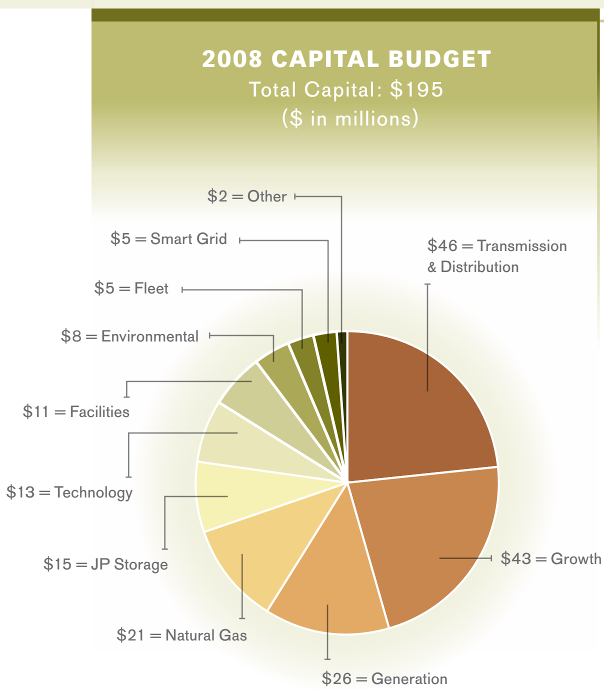
Our 30,000-square-mile service territory includes energy generation, transmission and distribution operations in four Western states.

Avista is well positioned to meet those growing demands for years ahead, and we'll do so as we always have – in ways that are environmentally sound and cost-effective. More than 50 percent of our generation comes from the clean, renewable rivers that are fed by snowpacks high in the mountains of Montana and Idaho. In 2007, we completed the renovation of unit 4 in the Cabinet Gorge hydroelectric plant on the Clark Fork River in Idaho, adding 10 megawatts (mW), bringing its total capacity to 267 mW. Updates at Noxon Rapids on the same river in Montana are just beginning and when complete in 2012, they will add 30 mW of incremental generation capability, stepping up our ability to meet renewable portfolio standards ahead of mandated timetables.

reliability

We've been purposeful in diversifying our mix of generating resources to reliably meet customer demand in the most cost-effective ways possible. We have a strong base of sustainable resources – hydro and biomass. With the planned upgrades to these plants, we are well-positioned to meet Washington state's renewable portfolio standards by 2012. At this time, wind generation is a small part of our resource mix, acquired through our contracts with the Stateline Wind Farm along the Washington-Oregon border. But it has the potential to play a larger role. We are working to identify and secure wind generation sites close to transmission lines within our service territory to maximize output and minimize the costs of getting the power to our customers. Natural gas plays an increasing role in our energy mix. We're strategically implementing actions – including seasonally timed acquisitions and enhanced storage capacity at the Jackson Prairie (Wash.) facility – that we believe will decrease the impacts of market price volatility for our natural gas customers.





Through careful planning and execution over the past five years – plus the anticipated addition of the Lancaster plant in Idaho in 2010 – we expect to have sufficient generating capacity until 2015. This gives us the flexibility to invest more in other infrastructure. Our nearly $200 million capital budget for 2008 will focus on refurbishing and upgrading our transmission and distribution systems, expanding our natural gas infrastructure in addition to upgrading the capacity of our existing hydroelectric facilities. Looking ahead, we expect to continue investing in our capital budget for the utility to assure reliability in our energy systems and to keep pace with regional growth and customer demand.

We're investing in natural gas infrastructure to keep pace with regional demands.

"Everyone can make a difference in our world and every little bit helps. Whether you're installing a compact fluorescent light bulb, choosing an ENERGY STAR® rated appliance, programming your thermostat or weatherizing your home — your efforts can make a difference right here at home, to the environment and to our world. As we all take part in becoming more energy efficient, our resources go farther."

www.avistautilities/everylittlebit.com

As we make these kinds of investments in our infrastructure, we will continue to go to our state regulators periodically to request rate relief and to provide reasonable rates of return. We are mindful of the impacts that price increases have on our customers, but preparing for the future and keeping the company financially strong are the right things to do for everyone.

This focus on the future by our employees has led to innovative and value-oriented outcomes. We've been an industry leader in implementing energy efficiency programs for our customers since 1978. To date, these programs have saved over 120 annual average mW of generation that didn't have to be created. That translates into more than 300,000 tons of carbon dioxide per year that wasn't emitted into our atmosphere.

We know that in spite of all we do to help customers wisely manage their energy use, there are those who need our assistance. Partnering with our customers, local and national organizations, and governments, we provided over $11.6 million in energy assistance funding during the 2006 – 2007 heating season.

Our commitment to doing the right thing includes assistance to seniors and other vulnerable customers.

ENERGY ASSISTANCE GRANTS
Heating Seasons 2004-05 / 2005-06 / 2006-07

Advantage IQ is an industry leader and helps increase long-term value for our investors.

Efficient energy use is the centerpiece of Advantage IQ's business. This subsidiary provides facility information and expense management services for over 400 businesses, representing approximately 200,000 sites in North America. In addition to processing and paying utility, telecom and waste invoices, Advantage IQ combines effective management and reporting tools to provide clients with accurate information necessary to drive operational and cost savings. In 2007 Advantage IQ received the ENERGY STAR® Sustained Excellence Award from the U.S. Environmental Protection Agency. This award recognizes Advantage IQ's continued commitment to energy efficiency by providing services and products that help businesses adopt smart energy practices.

Advantage IQ is a leader in the industry and has shown consistent growth in both customers and revenues. Strategic technological investment and operational enhancements are leading this business toward the goal of increasing long-term shareholder value for Avista.

ADVANTAGE IQ REVENUE | 2003 – 2007

"We cannot and should not stay where we are as a company. We must continue to work toward our goal of value creation."
– Gary Ely, 2000

For over 40 years, Gary Ely was a steadying and guiding influence on this company, through the good times and in times that challenged our very foundation. He's been a mentor, a leader and a servant leader throughout it all. His integrity, sound judgment and compassion for people shone brightly throughout his career, from an entry level draftsman to becoming chairman of the board. We stand today as a company that is stronger for his leadership.

CORPORATE

leadership

BOARD OF DIRECTORS

Erik J. Anderson, 49
President, Westriver Capital
Kirkland, Washington
Director since 2000

Kristianne Blake, 54
President, Kristianne Gates Blake, P.S.
Spokane, Washington
Director since 2000

Brian W. Dunham, 50
President & CEO
Northwest Pipe Co.
Portland, Oregon
Director since 2008

Roy Lewis Eiguren, 56
President
Eiguren Public Law & Policy, PLLC
Boise, Idaho
Director since 2002

Jack W. Gustavel, 68
Chairman & CEO
Idaho Independent Bank
Coeur d'Alene, Idaho
Director since 2003

John F. Kelly, 63
President & CEO
John F. Kelly & Associates
Coral Gables, Florida
Director since 1997

Scott L. Morris, 50
Chairman of the Board,
President & CEO
Avista Corp.
Spokane, Washington
Director since 2007

Michael L. Noël, 66
President, Noël Consulting Company
Prescott, Arizona
Director since 2004

Lura J. Powell, Ph.D., 57
President, Technology Strategies, Inc.
Richland, Washington
Director since 2003

Heidi B. Stanley, 51
Vice Chair, President & CEO
Sterling Savings Bank
Spokane, Washington
Director since 2006

R. John Taylor, 58
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
Roy L. Eiguren
John F. Kelly
R. John Taylor – Chair

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

Environmental, Safety & Security Committee
Erik J. Anderson
Roy L. Eiguren
Lura J. Powell – Chair

CORPORATE AND BUSINESS UNIT OFFICERS

Scott L. Morris, 50
Chairman of the Board,
President & CEO

Malyn K. Malquist, 55
Executive Vice President &
CFO

Marian M. Durkin, 54
Senior Vice President,
General Counsel &
Chief Compliance Officer

Karen S. Feltes, 52
Senior Vice President &
Corporate Secretary

Christy M. Burmeister-Smith, 51
Vice President, Controller &
Principal Accounting Officer

James M. Kensok, 49
Vice President & CIO

Don F. Kopczynski, 52
Vice President

David J. Meyer, 54
Vice President &
Chief Counsel for Regulatory
& Governmental Affairs

Kelly O. Norwood, 49
Vice President

Dennis P. Vermillion, 46
Vice President

Ann M. Wilson, 42
Vice President-Finance &
Treasurer

Roger D. Woodworth, 51
Vice President

Stuart A. Stiles, 47
President &
CEO of Advantage IQ

FINANCIAL AND OPERATING HIGHLIGHTS

(Dollars in Thousands Except Statistics and Per Share Amounts or as Otherwise Indicated)	2007	2006	2005
FINANCIAL RESULTS			
Operating revenues	$ 1,417,757	$ 1,506,311	$ 1,359,607
Operating expenses	1,279,328	1,306,751	1,211,953
Gain on sale of utility properties	–	–	4,093
Income from operations	138,429	199,560	151,747
Net income	38,475	72,941	44,988
Earnings per common share, diluted	0.72	1.46	0.92
Earnings per common share, basic	0.73	1.48	0.93
Dividends paid per common share	0.595	0.570	0.545
Book value per common share	$ 17.27	$ 17.41	$ 15.82
Average common shares outstanding	52,796	49,162	48,523
Actual common shares outstanding	52,909	52,514	48,593
Return on average common equity	4.2%	8.7%	5.9%
Common stock closing price	$ 21.54	$ 25.31	$ 17.71
OPERATING RESULTS			
Avista Utilities			
Retail electric revenues	$ 576,260	$ 554,136	$ 511,864
Retail kWh sales (in millions)	8,912	8,775	8,530
Retail electric customers at year-end	351,512	345,450	338,369
Wholesale electric revenues	$ 105,729	$ 126,208	$ 151,429
Wholesale kWh sales (in millions)	1,594	2,117	2,508
Sales of fuel	$ 12,910	$ 48,176	$ 41,831
Other electric revenues	16,231	18,863	17,988
Retail natural gas revenues	424,246	416,010	368,252
Wholesale natural gas revenues	142,167	93,221	58,074
Transportation and other natural gas revenues	$ 10,820	$ 11,324	$ 11,879
Total therms delivered (in thousands)	700,433	629,906	562,307
Retail natural gas customers at year-end	310,535	304,586	297,277
Net income	$ 43,822	$ 57,794	$ 52,299
Energy Marketing and Resource Management			
Gross margin (operating revenues less resource costs)	$ (7,135)	$ 33,414	$ 2,016
Net income (loss)	(11,877)	11,567	(8,621)
Advantage IQ			
Revenues	$ 47,255	$ 39,636	$ 31,748
Net income	6,651	6,255	3,922
Other			
Revenues	$ 20,598	$ 21,186	$ 18,532
Net loss	(121)	(2,675)	(2,612)
FINANCIAL CONDITION			
Total assets	$ 3,189,797	$ 4,056,508	$ 4,948,494
Long-term debt (including current portion)	948,833	976,459	1,029,514
Long-term debt to affiliated trusts	113,403	113,403	113,403
Preferred stock (subject to mandatory redemption)	–	26,250	28,000
Stockholders' equity	913,966	914,525	768,849

2007 Financial Report

sound leadership | *reliable energy*

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LONG LAKE DAM PENSTOCKS
Penstocks channel and increase the force of falling water in order to efficiently generate electricity. This year's financial report cover represents Avista's strength and energy, generating a powerful and positive outlook toward the future.

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), 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) 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;
- changes in wholesale energy prices that can affect, among other things, cash needed to purchase electricity, natural gas for our retail customers and natural gas fuel for electric generation, and the value of surplus energy sold, as well as 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;
- 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 future 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 future economic conditions in our service territory and the United States in general, including inflation or deflation;
- 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;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions;
- the effect of any change in our credit ratings;
- 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;
- 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.

RESTATEMENT OF 2006 AND 2005 FINANCIAL STATEMENTS

We restated our consolidated financial statements for 2006 and 2005 and related disclosures. During preparation of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, we determined that Statement of Financial Accounting Standards (SFAS) No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" was inadvertently not followed in connection with a plan under which benefits are provided to the beneficiaries of our former and current executive officers in case of death. We had not previously recognized the actuarial liability or costs relating to this plan in our financial statements since the plan's inception in 1989.

We determined that this accounting error was not material to our previously issued financial statements. As such, in accordance with the provisions of Securities and Exchange Commission Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," we reflected the correction of this error in subsequent financial statements including the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 and in all subsequent filings with the Securities and Exchange Commission. Our previously reported net income of $73.1 million and $45.2 million for 2006 and 2005 were each reduced by $0.2 million. For further information see "Note 31 of the Notes to Consolidated Financial Statements."

POTENTIAL HOLDING COMPANY FORMATION

In May 2006, our shareholders approved a proposal to proceed with a statutory share exchange, which would change our organization to a holding company structure. If the implementation of the holding company structure is approved by regulators on terms acceptable to us, it may be completed sometime in 2008. See further information at "Note 26 of the Notes to Consolidated Financial Statements."

BUSINESS SEGMENTS

We have three reportable business segments as follows:

- **Avista Utilities** – generation, transmission and distribution of electric energy and distribution of natural gas to retail customers, as well as wholesale purchases and sales of energy commodities. Avista Utilities is an operating division of Avista Corp. comprising our regulated utility operations.
- **Energy Marketing and Resource Management** – electricity and natural gas marketing, trading and resource management. 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. (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. Completion of this transaction effectively ends the majority of the operations of this business segment. This segment still owns natural gas storage facilities and has operating revenues and resource costs related to the power purchase agreement for a 270 megawatt (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.
- **Advantage IQ** – facility information and cost management services for multi-site customers. The activities of this business segment are conducted by Advantage IQ, Inc. (Advantage IQ), an indirect subsidiary of Avista Corp.

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. These activities are not a reportable business 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 $914.0 million as of December 31, 2007, of which $71.4 million represented our investment in Avista Capital. Our investment in Avista Capital decreased significantly in 2007 primarily due to the sale of substantially all of Avista Energy's contracts and ongoing operations and the subsequent dividends to Avista Corp. through 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):

	2007	2006	2005
Avista Utilities	$ 43,822	$ 57,794	$ 52,299
Energy Marketing and Resource Management	(11,877)	11,567	(8,621)
Advantage IQ	6,651	6,255	3,922
Other	(121)	(2,675)	(2,612)
Net income	$ 38,475	$ 72,941	$ 44,988

EXECUTIVE LEVEL SUMMARY

Overall

Our operating results and cash flows have been derived primarily from:

- regulated utility operations (Avista Utilities),
- energy trading, marketing and resource management activities (Avista Energy in the Energy Marketing and Resource Management segment), and
- facility information and cost management services for multi-site customers (Advantage IQ).

2007 was a year of repositioning our company with a focus on the future of our utility operations. Moody's Investors Service and Standard & Poor's recently 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 upgrade reflects several steps taken over the past few years to lower our business risk profile and improve financial metrics. The most recent significant steps were the sale of substantially all of Avista Energy's contracts and ongoing operations and our general rate case settlement in Washington.

Although we are pleased with the upgrades, it is important to note that we are at the lower end of the investment grade category and will continue to work towards improving our ratings. We intend to continue to focus on improving earnings and operating cash flows, controlling costs, reducing debt and debt service costs, while working to improve our credit ratings.

After closing costs and other adjustments, the Avista Energy transaction resulted in a pre-tax loss of $4.3 million. Proceeds from the transaction included cash consideration for the net assets acquired by Shell Energy and liquidation of the net current assets of Avista Energy not sold to Shell Energy (primarily receivables, restricted cash and deposits with counterparties). The majority of the $169 million of proceeds from the transaction were deployed into our regulated utility operations. Also, we retained natural gas storage rights and facilities for the period subsequent to April 2011 and the power purchase agreement for the Lancaster Plant for the period 2010 through 2026. We plan to use these assets and contracts in our utility operations, subject to future regulatory approval. The completion of this transaction lowers our corporate risk profile and should improve the stability of our earnings.

Our net income was $38.5 million for 2007 compared to $72.9 million for 2006. This decrease was primarily due to the net loss at Avista Energy (Energy Marketing and Resource Management segment) and lower earnings at Avista Utilities.

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.

Weather has a significant effect on our utility operations. Weather can impact customer demand and operating revenues and 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 operating revenues. In addition, below normal precipitation (particularly winter snowpack) and other streamflow conditions can negatively impact electric resource costs by decreasing hydroelectric generation capability and increasing our reliance on market purchases and thermal generation. Regional precipitation and snowpack conditions typically have a significant effect on the wholesale price of electricity. In addition, high demand for electricity will generally increase both the quantity needed and price of fuel for electric generation and wholesale electric market prices.

Our hydroelectric generation was 96 percent of normal in 2007. Our hydroelectric generation was below normal (based on a 70-year average) for six of the past eight years. For 2008, we forecast hydroelectric generation to be slightly above normal. This 2008 forecast will be revised based on precipitation, temperatures and other variables during the year.

We are subject to electric and natural gas commodity price risk. In general, price risk is driven by fluctuation in the market price of the commodity needed, held or traded. Changes in energy commodity prices have a significant effect on our liquidity, as well as the market value of derivative assets and liabilities. We have 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 above the level currently recovered in retail rates during periods when we must purchase energy, power and natural gas deferral balances will increase. This would negatively affect our operating cash flows and liquidity until such costs are recovered from customers.

The decision of the Washington Utilities and Transportation Commission (WUTC) in late 2006 to deny our request for more timely recovery of transmission and generation investments presented a significant challenge in 2007 for us to replace the rate relief we had anticipated. Our challenge was compounded by below normal hydroelectric generation. However, the WUTC approved rate relief for 2008 as discussed below.

Our utility net income was $43.8 million for 2007, a decrease from $57.8 million for 2006 primarily due to a decrease in gross margin (operating revenues less resource costs). The decrease was also due to the disallowance of unamortized debt repurchase costs in the Washington general rate case settlement, an increase in other operating expenses and an increase in depreciation and amortization. This was partially offset by a decrease in interest expense. The decrease in gross margin was primarily due to the difference in electric resource costs as compared to the amount included in base retail rates. We recognized an expense of $8.5 million under the Energy Recovery Mechanism (ERM) in Washington for 2007 compared to a benefit of $2.6 million under the ERM for 2006. The increase in electric resource 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).

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 $205.8 million for 2007. We expect utility capital expenditures to be $200 million for 2008.

In October 2007, we reached a settlement in our Washington general rate case that was approved by the WUTC in December 2007. Electric rates for our Washington customers increased by 9.4 percent (designed to increase annual revenues by $30.2 million) and natural gas rates increased by 1.7 percent (designed to increase annual revenues by $3.3 million) effective January 1, 2008. In February 2008, we reached a settlement in our Oregon general rate case, which is designed to increase annual revenues by $0.9 million on April 1, 2008 and $1.4 million on November 1, 2008. This settlement is subject to approval by the Public Utility Commission of Oregon (OPUC).

Based primarily on the following, we expect utility net income to increase in 2008 as compared to 2007:

- Implementation of the general rate increase in Washington effective January 1, 2008, which includes resetting the base level of power supply costs used in the ERM calculations. Given the forecasted improvement in hydroelectric generation and the resetting of the base level of power supply costs used in the ERM calculations, we project a benefit under the ERM in 2008.
- The write-down of a turbine and the disallowance of debt repurchase costs in 2007. These charges should not recur in 2008.
- A decrease in interest expense due to the maturity of $273 million of 9.75 percent Senior Notes on June 1, 2008. We will issue new debt to fund a significant portion of the maturing debt and it should be at a substantially lower rate. In 2004, we entered into forward-starting interest rate swap agreements effectively locking in market fixed interest rates, which were relatively low compared to historical interest rates, for $125 million of our forecasted debt issuances in 2008.
- We expect slightly above normal hydroelectric generation and an increase in electric and natural gas retail loads in 2008.

Energy Marketing and Resource Management (Avista Energy)

On June 30, 2007 we sold substantially all of the contracts and ongoing operations of this business. 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.

Our earnings and cash flows from this business segment were by nature subject to significant variability because they were derived primarily from the day-to-day trading of electricity and natural gas and optimization of assets owned by other entities, rather than predictable long-term revenue streams. Also, these activities were for the most part subject to mark-to-market accounting. However, this is different from the required accounting for natural gas storage and certain other assets and contracts. As such, our earnings from Avista Energy were subject to variability caused by the differences between the estimated market value and the required accounting for these assets and contracts.

Primarily through Avista Energy, we are involved in a number of legal and regulatory proceedings and complaints with respect to power markets in the western United States that remain unresolved. However, we believe that we have adequate reserves established for refunds that may be ordered. Any potential refunds or obligations arising from western power market issues (or any other contingent matters) were retained by Avista Energy.

The Energy Marketing and Resource Management segment had a net loss of $11.9 million for 2007 compared to net income of $11.6 million for 2006. The difference between the estimated market value and the required accounting for certain contracts and physical assets under management increased the net loss by $6.4 million from this segment for 2007 and reduced net income by $2.2 million for 2006.

The lower than expected results from this segment for 2007 were primarily due to:

- underperformance on the power side of the business,
- losses on the power purchase agreement for the Lancaster Plant, and
- a loss on the net assets sold to Shell Energy.

Advantage IQ

Our subsidiary, Advantage IQ, had net income of $6.7 million for 2007, an increase from $6.3 million for 2006. The increase for 2007 as compared to 2006 was primarily due to an increase in operating revenues as a result of customer growth and an increase in interest earnings on funds held for customers, partially offset by increased operating expenses from expanding operations. Earnings growth for Advantage IQ was limited in 2007 due to expenses incurred for consulting services during the second and third quarters. Net income may decrease slightly in 2008 as compared to 2007. Customer growth and operating efficiencies are expected to be offset by the recent decline in short-term interest rates, which will decrease Advantage IQ's interest earnings on funds held for customers.

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 $0.1 million for 2007 compared to a net loss of $2.7 million for 2006. This improvement in results on a year-to-date basis was partially due to net gains on certain long-term venture fund investments in 2007 as compared to net losses in 2006, as well as income tax adjustments recorded in 2006.

Liquidity and Capital Resources

We have a committed line of credit in the total amount of $320.0 million with an expiration date of April 2011. There were not any cash borrowings outstanding; however, there were $34.8 million in letters of credit outstanding as of December 31, 2007.

In March 2007, we amended our accounts receivable sales facility to extend the termination date to March 2008. We expect to renew this facility before the March 2008 expiration. Under this facility, we can sell without recourse, on a revolving basis, up to $85.0 million of accounts receivable. We had sold $85.0 million of accounts receivable under this facility as of December 31, 2007.

We have long-term debt maturities of $318 million in 2008, the majority of which is $273 million of 9.75 percent Senior Notes that mature on June 1, 2008. We will issue new debt securities to fund a significant portion of these requirements in 2008; however, the new securities should have a substantially lower interest rate. We also have $83.7 million of Pollution Control Bonds that are subject to remarketing on December 30, 2008. These bonds are included in the current portion of long-term debt because they are puttable at the option of the security holders on that date. If the bonds cannot be successfully remarketed on that date, we will be required to purchase the outstanding bonds. In addition, we have $25 million of Secured Medium-Term Notes with a maturity date of June 2028 that are puttable at the option of the security holders in June 2008.

Excluding long-term debt obligations in 2008, we expect net cash flows from operating activities and our $320.0 million committed line of credit 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. During the second half of 2008, we plan to begin issuing common stock under this sales agency agreement.

AVISTA UTILITIES – ELECTRIC RESOURCES

As of December 31, 2007, our generation facilities had a total net capability of 1,771 MW, of which 55 percent was hydroelectric and 45 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 6 of the Notes to Consolidated Financial Statements" for information with respect to the resource optimization process.

AVISTA UTILITIES – REGULATORY MATTERS

General Rate Cases

In recent years (particularly in 2007), we have generally not earned our authorized rates of return in our regulated utility operations. 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. We are planning to file general rate cases in both Washington and Idaho in 2008.

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 2008	8.20%	10.2%	46%
Idaho electric and natural gas	September 2004	9.25%	10.4%	43%
Oregon natural gas	April 2008 (1)	8.21%	10.0%	50%

(1) Based on a settlement agreement that is subject to final approval by the OPUC.

We filed a general rate case in Washington in April 2007 requesting rate increases averaging 15.9 percent for electric (designed to increase annual revenues by $51.1 million) and 2.3 percent for natural gas (designed to increase annual revenues by $4.5 million). In May 2007, the WUTC issued an order that consolidated our request for an accounting order regarding the accounting for debt repurchase costs into the general rate case filing.

In October 2007, we reached an all-party settlement that resolved all issues in our Washington general rate case. The settlement was approved by the WUTC in December 2007. As agreed to in the settlement, on January 1, 2008, electric rates for our Washington customers increased by an average of 9.4 percent, which is 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 is designed to increase annual revenues by $3.3 million. Approximately one-half of the increase in natural gas rates is related to storage-capacity release revenues recovered from a third party. This is a transfer between revenue classes and has no impact on net income.

The settlement is based on a rate of return of 8.2 percent with a common equity ratio of 46 percent and a 10.2 percent return on equity. Our original request was based on a rate of return of 9.39 percent with a common equity ratio of 47.8 percent and an 11.3 percent return on equity.

In addition, we agreed to write off $3.8 million of unamortized debt repurchase costs in 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.

We filed a natural gas general rate case in Oregon in October 2007. In this general rate case, we requested to increase natural gas rates for our Oregon customers by an average of 2.3 percent, which is designed to increase annual revenues by $3.0 million. Our request was based on a proposed rate of return of 8.98 percent with a common equity ratio of 51.2 percent and an 11.0 percent return on equity. In December 2007, we entered into a settlement agreement with all parties, including the Staff of the OPUC, the Citizen's Utility Board and the Northwest Industrial Gas Users for the purpose of resolving the cost of capital components. Pursuant to the settlement, the parties agreed to a rate of return of 8.21 percent with a common equity ratio of 50 percent and a 10.0 percent return on equity. In February 2008, we reached a settlement with all parties resolving the remaining issues in the case. The settlement, which is subject to approval from the OPUC, provides for natural gas rate increases of 0.7 percent effective April 1, 2008 (designed to increase annual revenues by $0.9 million) and an additional 1.1 percent effective November 1, 2008 (designed to increase annual revenues by an additional $1.4 million). The November 1, 2008 increase is related to placing into service a natural gas construction project and the allocation of natural gas storage assets to our Oregon operations and may be adjusted downward if actual costs are lower than currently estimated. Concurrent with the general rate case, we also filed a petition to revise our book depreciation rates, which reduces depreciation expense in Oregon by $3.1 million. The OPUC approved this request on an interim basis effective January 1, 2008 until review of the filing is completed and a final decision is issued by the OPUC.

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. If we do not meet those targets, it could result in a reduction to base rates of 2 percent for each target. The calculation of the utility equity component is essentially the ratio of our total consolidated common equity to total capitalization excluding, in each case, our investment in Avista Capital. The utility equity component was approximately 45 percent as of December 31, 2007.

Oregon Senate Bill 408

The OPUC issued amended rules in September 2007 related to Oregon Senate Bill 408 (OSB 408). OSB 408 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.

The rules provide for an "apportionment method" that uses a three-factor formula consisting of property, payroll and sales for regulated operations of the utility in Oregon as the numerator, and these same factors for the consolidated company as the denominator, to determine the amount of consolidated taxes paid that are properly attributed to Oregon operations. Under the rules, we determine the least of:

- the properly attributed amount of taxes paid using the apportionment method,
- the amount of taxes determined on a stand-alone basis for Oregon operations, and
- total consolidated taxes paid.

We then compare this amount to taxes collected in rates to determine if a refund or surcharge is required.

As required by OPUC orders, we (along with other utilities in Oregon) filed a private letter ruling request with the Internal Revenue Service (IRS) in December 2006. The private letter ruling request sought guidance on whether OSB 408 and the related OPUC orders violate normalization rules for accounting for income taxes. The OPUC order issued in September 2007 required that all of the affected utilities in Oregon file amended private letter ruling requests by November 30, 2007 to reflect the latest amendments to the rules. In January 2008 the IRS issued its finding that the OSB 408 rules, as represented to them in our applications, meets their tax normalization requirements, and presents no violation. On October 15, 2007, we filed the 2006 tax report with the OPUC which shows a liability for a potential refund. We recorded a total liability for potential refunds of approximately $3.6 million for 2006 and 2007. In February 2008, we reached a settlement-in-principle with respect to the refund liability for 2006. The settlement is subject to approval by the OPUC, with a decision expected on or before April 11, 2008.

Natural Gas Decoupling

In February 2007, the WUTC approved the implementation of a natural gas decoupling mechanism. Decoupling separates the direct link between natural gas sales volume and the recovery of the fixed cost of providing service to our customers. 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. 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 three-year "pilot" that began in January 2007. A rate adjustment in any one year would be limited to no more than 2 percent. Our first decoupling rate adjustment became effective November 1, 2007. The rate adjustment is designed to recover $0.3 million over a twelve-month period or a 0.2 percent increase for residential and commercial customers, representing 80 percent of the lost margin for the period January through June 2007.

Accounting for Debt Repurchase Costs

The WUTC staff raised questions and requested information regarding our method of amortization of costs related to debt repurchased between 2002 and 2006. After discussions with the WUTC staff, we agree that the costs associated with debt repurchases beginning in 2002 should have been accounted for in accordance with Federal Energy Regulatory Commission (FERC)

General Instruction 17 (FERC 17). In May 2007, the WUTC issued an order that consolidated this issue into our April 2007 general rate case filing. In the April general rate case filing, we agreed that costs associated with any new repurchases of debt would be accounted for in accordance with FERC 17, and in the event we desire to account for the cost of new debt repurchases differently than prescribed in FERC 17, we would request an accounting order from the WUTC prior to the repurchase. Under FERC 17, debt repurchase costs 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 can be amortized over the life of the new debt. We have amortized debt repurchase costs over the average remaining maturity of outstanding debt and these costs are currently recovered through retail rates as a component of interest expense. Pursuant to a settlement agreement in our Washington general rate case, we agreed to write off $3.8 million of unamortized debt repurchase costs for premiums paid to repurchase debt prior to its scheduled maturity.

Power Cost Deferrals and Recovery Mechanisms

The ERM is an accounting method used to track certain differences between actual power supply costs and the amount included in base retail rates for our Washington customers.

This difference in power supply costs primarily results from changes in:

- short-term wholesale market prices,
- 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 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 will share annual power supply cost variances between $4.0 million and $10.0 million with customers. As such, 50 percent of the annual power supply cost variance in this range is deferred for future surcharge or rebate to customers and we incur the cost of, or receive 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:

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%

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.

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. In June 2007, the IPUC approved continuation of the PCA mechanism with the annual rate adjustment provision. 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, increased from 2.5 percent to 4.7 percent on October 1, 2007.

The following table shows activity in deferred power costs for Washington and Idaho during 2006 and 2007 (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

Purchased Gas Adjustments

Effective November 1, 2007, natural gas rates decreased:

- 6.0 percent in Washington,
- 4.6 percent in Idaho, and
- 1.7 percent in Oregon.

These natural gas rate decreases are designed to pass through changes in purchased natural gas costs to our customers with no change in gross margin (operating revenues less resource costs) or net income. In Oregon, there is an ongoing review of the PGA mechanism used by all natural gas distribution companies in Oregon (including Avista Corp.). The outcome of this review could impact our PGA mechanism and natural gas purchasing and hedging strategies in Oregon. Total net deferred natural gas costs were $2.4 million (an asset of $6.2 million and a liability of $3.8 million) as of December 31, 2007, a decrease from $18.3 million as of December 31, 2006 primarily due to recovery from customers during 2007.

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, Energy Marketing and Resource Management, Advantage IQ and the other businesses) that follow this section.

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:

- a decrease of $4.5 million in the Energy Marketing and Resource Management segment due to the sale of Avista Energy's ongoing operations, partially offset by the loss on the sale,
- an increase of $6.8 million for Advantage IQ due to expanding operations and consulting services, and
- a decrease of $1.0 million in the other businesses due to lower operating expenses at AM&D and the accrual of an environmental liability at Avista Development during 2006.

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 (Other), 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.

2006 compared to 2005

Utility revenues increased $106.6 million to $1,267.9 million due to increases in:

- natural gas revenues of $82.3 million primarily due to the increased volume of wholesale natural gas sales and an increase in retail natural gas rates, and
- electric revenues of $24.3 million reflecting increased retail revenues and sales of fuel, partially offset by decreased wholesale revenues.

Non-utility energy marketing and trading revenues increased $29.5 million to $177.6 million primarily due to an increase of $32.6 million in net trading margin on contracts accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. This was partially offset by a decrease of $3.9 million in revenues from sales of natural gas to commercial and industrial end-user customers (a decrease through Avista Energy Canada offset by an increase in revenues from Montana customers).

Other non-utility revenues increased $10.5 million to $60.8 million as a result of increased revenues from:

- Advantage IQ of $7.9 million primarily due to customer growth as well as an increase in interest earnings on funds held for customers, and
- the other businesses of $2.7 million primarily due to increased sales at AM&D.

Utility resource costs increased $82.0 million primarily due to increased:

- natural gas resource costs of $79.0 million reflecting an increase in the volume of purchases, as well as the amortization of deferred natural gas costs (due to recovery from customers), and
- electric resource costs of $3.0 million reflecting an increase in base resource costs as set forth in the Washington general rate case implemented on January 1, 2006, as well as an increase in fuel for generation and other fuel costs (representing the economic sale of fuel that was not used in generation).

Utility other operating expenses increased $5.7 million primarily due to increased:

- stock and performance based compensation of $2.1 million,
- distribution maintenance costs of $2.1 million, and
- electric sales and service costs of $1.1 million.

Utility taxes other than income taxes increased $1.8 million primarily due to increased retail electric and natural gas revenues and related taxes, partially offset by a decrease in property taxes.

Non-utility resource costs decreased $1.9 million primarily due to decreased resource costs for Avista Energy Canada and partially due to a decrease in transportation and transmission costs. This was partially offset by a change in natural gas inventory and resource costs for natural gas sales to customers in Montana.

Other non-utility operating expenses increased $6.9 million primarily due to increased:

- incentive compensation at Avista Energy due to increased earnings,
- operating expenses for Advantage IQ due to expanding operations, and
- operating expenses in the other businesses.

Interest expense increased $2.5 million primarily due to our issuance of fixed rate long-term debt that replaced variable rate short-term debt (which had relatively low interest rates in 2005) in the fourth quarter of 2005. Although we believe this was a prudent long-term financing decision, it increased interest expense for 2006 as compared to 2005.

Interest expense to affiliated trusts increased $0.9 million due to increased interest rates on variable rate debt.

Capitalized interest increased $1.2 million due to increased utility construction activity and the associated increase in construction work in progress balances. Although our utility capital expenditures decreased in 2006 as compared to 2005, a significant portion of 2005 expenditures did not have any associated capitalized interest. This included the acquisition of the remaining interest in Coyote Springs 2 and the repurchase of our corporate headquarters and central operating facility in Spokane.

Income taxes increased $16.2 million primarily due to increased income before income taxes. Our effective tax rate was 36.5 percent for 2006 compared to 36.4 percent for 2005.

AVISTA UTILITIES

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.

2006 compared to 2005

Net income for the utility was $57.8 million for 2006 compared to $52.3 million for 2005. Utility income from operations was $177.0 million for 2006 compared to $165.1 million for 2005. This increase in income from operations was primarily due to increased gross margin (operating revenues less resource costs). The increase in gross margin was partially offset by:

- an increase in utility taxes other than income taxes (due to increased retail electric and natural gas revenues and related taxes, partially offset by a decrease in property taxes),
- an increase in other utility operating expenses (primarily stock and performance based compensation, distribution maintenance costs and electric sales and service costs), and
- the $4.1 million pre-tax gain related to the sale of the South Lake Tahoe natural gas distribution properties in 2005.

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	
	2006	2005	2006	2005	2006	2005
Operating revenues	$ 747,383	$ 723,112	$ 520,555	$ 438,205	$ 1,267,938	$ 1,161,317
Resource costs	346,980	343,945	404,666	325,651	751,646	669,596
Gross margin	$400,403	$ 379,167	$ 115,889	$ 112,554	$ 516,292	$ 491,721

Utility operating revenues increased $106.6 million and utility resource costs increased $82.0 million, which resulted in an increase of $24.6 million in gross margin. The gross margin on electric sales increased $21.2 million and the gross margin on natural gas sales increased $3.3 million. The increase in our electric gross margin was primarily due to a decrease in electric resource costs as compared to the amount included in base retail rates resulting in the benefit of $2.6 million (of the current $4.0 million deadband) of power supply costs in Washington below the amount included in base retail rates during 2006. In 2005, we expensed the full previous $9.0 million deadband of power supply costs above the amount included in base retail rates in Washington. The improvement in power supply costs for 2006 was primarily a result of improved hydroelectric generation from higher than normal precipitation resulting in increased streamflows to our hydroelectric generating facilities.

The increase in electric gross margin was also partially due to:

- the sale of claims we had against Enron-related entities in the first quarter of 2006,
- the Washington general rate increase implemented on January 1, 2006, and
- customer growth.

The increase in natural gas gross margin was primarily due to customer growth in our Washington, Idaho and Oregon service territories, partially offset by the sale of our South Lake Tahoe natural gas operations in April 2005.

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	
	2006	2005	2006	2005
Residential	$ 234,714	$ 211,934	3,578	3,420
Commercial	221,193	203,480	3,110	2,994
Industrial	92,961	91,552	2,062	2,091
Public street and highway lighting	5,268	4,898	25	25
Total retail	554,136	511,864	8,775	8,530
Wholesale	126,208	151,429	2,117	2,508
Sales of fuel	48,176	41,831	–	–
Other	18,863	17,988	–	–
Total	$ 747,383	$ 723,112	10,892	11,038

Retail electric revenues increased $42.3 million due to an increase in:

- revenue per MWh (increased revenues $26.8 million) primarily due to the Washington general rate increase of 7.5 percent as well as a 1.0 percent increase in the ERM surcharge, both of which were implemented on January 1, 2006, and
- total MWhs sold (increased revenues $15.5 million) primarily due to customer growth and partially due to an increase in use per customer (due to warmer weather during the summer cooling season, partially offset by warmer weather during the winter heating season).

Wholesale electric revenues decreased $25.2 million due to a decrease in sales:

- volumes (decreased revenues $23.3 million) consistent with decreased wholesale purchases and decreased resource optimization activities, and
- prices (decreased revenues $1.9 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 $6.3 million as a greater percentage of our fuel purchases were not used in generation (during the first quarter of 2006).

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	
	2006	2005	2006	2005
Residential	$ 257,753	$ 229,737	192,833	199,433
Commercial	146,581	126,648	120,989	122,981
Industrial	11,676	11,867	11,040	13,534
Total retail	416,010	368,252	324,862	335,948
Wholesale	93,221	58,074	154,884	72,903
Transportation	6,499	7,601	149,717	152,990
Other	4,825	4,278	443	466
Total	$ 520,555	$ 438,205	629,906	562,307

Natural gas revenues increased $82.4 million due to an increase in retail and wholesale natural gas revenues. The $47.8 million increase in retail natural gas revenues was primarily due to higher retail rates (increased revenues $62.0 million), partially offset by reduced volumes (decreased revenues $14.2 million). During October and November of 2005, we increased natural gas rates (with regulatory approval) in response to an increase in natural gas costs. We sold less retail natural gas in 2006 primarily due to the sale of our South Lake Tahoe properties and a decrease in use per customer (due to warmer weather), partially offset by customer growth in our other service territories. The increase in our wholesale revenues of $35.1 million reflects the balancing of loads and resources and the sale of resources in excess of load requirements as part of the natural gas procurement process that was implemented effective April 1, 2005.

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	
	2006	2005	2006	2005
Residential	300,940	294,036	267,345	265,294
Commercial	37,912	37,282	31,746	31,652
Industrial	1,388	1,408	295	307
Public street and highway lighting	425	421	–	–
Total retail customers	340,665	333,147	299,386	297,253

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

	2006	2005
Electric resource costs:		
Power purchased	$ 150,719	$ 186,703
Power cost amortizations, net of deferrals	29,259	24,209
Fuel for generation	109,723	93,034
Other fuel costs	50,881	36,636
Other regulatory amortizations, net	(6,199)	(6,532)
Other electric resource costs	12,597	9,895
Total electric resource costs	346,980	343,945
Natural gas resource costs:		
Natural gas purchased	371,142	335,796
Natural gas amortizations (deferrals), net	28,426	(13,912)
Other regulatory amortizations, net	5,098	3,767
Total natural gas resource costs	404,666	325,651
Total resource costs	$ 751,646	$ 669,596

Power purchased decreased $36.0 million primarily due to a decrease in the:

- price of power purchases (decreased costs $17.9 million) due to overall decreases in wholesale markets, and
- volume of power purchases (decreased costs $18.1 million) primarily due to increased hydro generation.

Net amortization of deferred power costs was $29.3 million for 2006 compared to $24.2 million for 2005. During 2006, we recovered (collected as revenue) $30.3 million of previously deferred power costs in Washington and $4.6 million in Idaho. During 2006, we deferred $5.7 million of power costs in Idaho above the amount included in base retail rates. We did not defer any power costs in Washington during 2006, as power supply costs were within the $4.0 million deadband under the ERM.

Fuel for generation increased $16.7 million primarily due to higher natural gas fuel prices, partially offset by a decrease in thermal generation volumes.

Other fuel costs increased $14.2 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 increase in other fuel costs was primarily due to a reduced percentage of fuel used in generation and higher natural gas fuel prices.

The expense for natural gas purchased for sale to customers increased $35.3 million primarily due to an increase in total therms purchased (increased costs $54.8 million). This was due to an increase in wholesale sales as part of the balancing of loads and resources with the natural gas procurement process, partially offset by a slight decrease in retail sales volumes. This was partially offset by a decrease in the cost of natural gas (decreased costs $19.5 million). During 2006, we amortized $28.4 million of deferred natural gas costs compared to net deferrals of $13.9 million for 2005. The change reflects higher retail rates (through purchased gas cost adjustments) to collect deferred natural gas costs from customers.

ENERGY MARKETING AND RESOURCE MANAGEMENT

The Energy Marketing and Resource Management segment primarily includes the results of Avista Energy. On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations. Completion of this transaction effectively ended the majority of the operations of this business segment.

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.

Avista Energy reports the net margin on derivative commodity instruments held for trading as operating revenues. Revenues from contracts that are not derivatives under SFAS No. 133 and derivative commodity instruments not held for trading are reported on a gross basis in operating revenues. Costs from contracts that are not derivatives under SFAS No. 133 and derivative commodity instruments not held for trading, are reported on a gross basis in resource costs.

The following table presents our net realized gains and net unrealized gains (losses) from Avista Energy for the year ended December 31 (dollars in thousands):

	2007	2006	2005
Net realized gains	$ 17,459	$ 31,904	$ 40,142
Net unrealized gains (losses)	(24,594)	1,510	(38,126)
Total gross margin (operating revenues less resource costs)	$ (7,135)	$ 33,414	$ 2,016

Overall segment results for 2007 compared to 2006

This segment had a net loss of $11.9 million for 2007 compared to net income of $11.6 million for 2006. The difference between the estimated market value and the required accounting for certain contracts and physical assets under management increased the net loss by $6.4 million from this segment for 2007 and reduced net income by $2.2 million for 2006. The lower than expected results from this segment for 2007 were primarily due to:

- underperformance on the power side of the business,
- losses on the power purchase agreement for the Lancaster Plant, and
- a loss on the net assets sold to Shell Energy.

Total assets for this segment decreased $986.5 million from December 31, 2006 to December 31, 2007 as a result of the sale of contracts to Shell Energy and the liquidation of assets not sold to Shell Energy. The remaining assets in this segment of $30.7 million are primarily natural gas storage and deferred income taxes.

Overall segment results for 2006 compared to 2005

The Energy Marketing and Resource Management segment had net income of $11.6 million for 2006 compared to a net loss of $8.6 million for 2005. The increase in net income for 2006 as compared to 2005 was primarily due to the improved results from natural gas trading activities and the continued execution of profitable transactions in power trading and other asset management and optimization activities. The difference between the estimated market value and the required accounting for certain contracts and physical assets under management of Avista Energy reduced our net income by an estimated $2.2 million for 2006. Our net loss for 2005 for this segment was due to losses in Avista Energy's natural gas portfolio. Our net loss for 2005 for this segment was reduced by an estimated $0.4 million due to the effects of differences between the estimated market value and the required accounting for certain energy contracts and physical assets under management of Avista Energy.

Analysis of operating revenues and resource costs for 2007 compared to 2006

Operating revenues decreased $116.0 million to $61.5 million primarily due to a decrease of $60.3 million in net trading margin on contracts accounted for under SFAS No. 133 and a $63.2 million decrease from sales of natural gas to commercial and industrial end-user customers (both through Avista Energy Canada and to Montana customers). 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.

Resource costs decreased $75.5 million primarily due to decreased resource costs related to sales of natural gas to commercial and industrial end-user customers, and a change in natural gas inventory. 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.

Our gross margin (operating revenues less resource costs) from Avista Energy was a loss of $7.1 million for 2007 compared to a gain of $33.4 million for 2006. The decrease was primarily due to underperformance on the power side of the business, losses on the power purchase agreement for the Lancaster Plant, and the difference between the estimated market value and the required accounting for certain contracts and physical assets under management.

The remaining operating revenues and resource costs for this segment 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. Beginning in 2010 through 2026, the rights and obligations of the power purchase agreement for the Lancaster Plant will be contracted to Avista Energy. We expect that these rights and obligations will be transferred to our regulated utility, subject to future approval by the WUTC and the IPUC.

Analysis of operating revenues and resource costs for 2006 compared to 2005

Operating revenues from this segment increased $10.1 million and resource costs decreased $21.3 million resulting in an increase in our gross margin of $31.4 million.

Operating revenues increased primarily due to an increase of $32.6 million in net trading margin on contracts accounted for under SFAS No. 133, partially offset by decreased revenues of:

- $3.9 million from sales of natural gas to commercial and industrial end-user customers (a decrease through Avista Energy Canada offset by an increase in revenues from Montana customers), and
- $19.4 million under the Agency Agreement with Avista Utilities as natural gas procurement operations were transitioned to Avista Utilities effective April 1, 2005.

Resource costs decreased primarily due to decreased resource costs:

- under the Agency Agreement with Avista Utilities,
- related to sales of natural gas to commercial and industrial end-user customers (a decrease through Avista Energy Canada, partially offset by increases for Montana customers), and
- for transportation and transmission costs.

This was partially offset by a change in natural gas inventory.

Our gross margin (operating revenues less resource costs) from Avista Energy was a gain of $33.4 million for 2006 compared to $2.0 million for 2005. The increase was primarily due to:

- unrealized losses associated with the accounting for our management of natural gas inventory in 2005, and
- improved results from our natural gas trading activities (which had significant losses in 2005).

Our net realized gains from Avista Energy decreased to $31.9 million for 2006 from $40.1 million for 2005. The decrease in our net realized gains was primarily due to:

- decreased net gains on physical electric transactions, and
- increased net losses on settled financial transactions.

This was partially offset by decreased net losses on physical natural gas transactions.

Our total mark-to-market adjustment from this segment was a net unrealized gain of $1.5 million for 2006 compared to a net unrealized loss of $38.1 million for 2005.

Energy trading activities and positions

The following table summarizes information for trading activities at Avista Energy during 2007 (dollars in thousands):

	Electric Assets net of Liabilities	Natural Gas Assets net of Liabilities	Total Unrealized Gain (Loss)
Fair value of contracts as of December 31, 2006	$ 34,044	$ (507)	$ 33,537
Less contracts settled during 2007 (1)	(25,080)	7,792	(17,288)
Less contracts sold to Shell Energy (2)	(13,571)	5,670	(7,901)
Fair value of new contracts when entered into during 2007 (3)	–	–	–
Change in fair value due to changes in valuation techniques (4)	–	–	–
Change in fair value attributable to market prices and other market changes	4,607	(12,955)	(8,348)
Fair value of contracts as of December 31, 2007	$ –	$ –	$ –

(1) *Contracts settled during 2007 include those contracts that were open in 2006 but settled during 2007 as well as new contracts entered into and settled during 2007. Amount represents net realized gains associated with these settled transactions.*

(2) *Represents the estimated fair value of the contracts sold to Shell Energy on June 30, 2007.*

(3) *We did not enter into any origination transactions during 2007 in which we recognized any dealer profit or mark-to-market gain or loss at inception.*

(4) *During 2007, we did not experience a change in fair value due to changes in valuation techniques.*

ADVANTAGE IQ

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.

2006 compared to 2005

Net income for Advantage IQ was $6.3 million for 2006 compared to $3.9 million for 2005. Operating revenues increased $7.9 million and operating expenses increased $4.4 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. The increase in interest earnings on funds held for customers was due in part to an increase in interest rates. The increase in operating expenses primarily reflects increased labor costs necessary to serve an expanding customer base. In 2006, Advantage IQ processed bills totaling $10.8 billion, an increase of $1.5 billion, or 16 percent, as compared to 2005.

OTHER BUSINESSES

2007 compared to 2006

The net loss from these operations was $0.1 million for 2007 compared to a net loss of $2.7 million for 2006. Operating revenues decreased $0.6 million and operating expenses decreased $1.5 million. Net income for AM&D was $0.5 million for 2007, an increase from $0.3 million for 2006. With respect to overall results from these businesses, the improvement was due to:

- the accrual for an environmental liability in 2006,
- gains on certain long-term venture fund investments in 2007 compared to losses in 2006, and
- certain tax adjustments recorded in 2006.

2006 compared to 2005

The net loss from these businesses was $2.7 million for 2006 compared to a net loss of $2.6 million for 2005. Operating revenues increased $2.7 million and operating expenses increased $1.8 million. Net income for AM&D was $0.3 million for 2006 compared to a net loss of $0.8 million for 2005. With respect to overall results from these businesses, the improvement for AM&D was offset by:

- the accrual for an environmental liability in 2006,
- an increase in the loss on certain investments not related to AM&D, and
- certain income tax adjustments recorded in 2006.

NEW ACCOUNTING STANDARDS

In June 2006, the Financial Accounting Standards Board (FASB) issued 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. We adopted FIN 48 in the first quarter of 2007. The adoption of FIN 48 did not have a cumulative effect on our financial condition and results of operations. See Notes 2 and 12 of the "Notes to Consolidated Financial Statements" for further information.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which provides enhanced guidance for using fair value to measure assets and liabilities. We will be required to adopt SFAS No. 157 in 2008. We do not expect SFAS No. 157 to have a material impact on our financial condition and results of operations. However, we will have expanded disclosures with respect to fair value measurements.

In February 2007, the FASB issued 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 will be required to adopt SFAS No. 159 in 2008. We do not plan to use the fair value option under SFAS No. 159 and as such do not expect SFAS No. 159 to have any impact on our financial condition and results of operations.

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 from 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 are evaluating the impact SFAS No. 160 will have on our financial condition and results of operations.

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 issuance 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, are 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 the Finance Committee to ensure 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 Finance Committee has established investment allocation percentages by asset classes as disclosed in "Note 11 of the Notes to Consolidated Financial Statements."

Pension costs (including the Supplemental Executive Retirement Plan (SERP)) were $14.3 million for 2007, $14.5 million for 2006 and $13.4 million for 2005. 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 2006, the form of payment election assumption was analyzed based upon historical trends and future projections. We revised the form of payment election to assume that 5 percent of retirees and 50 percent of vested terminated participants will elect a lump sum payment, based upon the analysis. The form of payment election assumption previously assumed that 50 percent of retirees and vested terminated participants would elect a lump sum payment. The change resulted in an increase of $13.2 million to the pension benefit obligation as of December 31, 2006. The change will also increase future years' pension costs.

We have not made any changes to pension plan provisions in 2007, 2006 and 2005 that have had any significant effect on our recorded pension plan amounts. We have revised the key assumption of the discount rate in 2007 and 2006, and the key assumption of the expected long-term return on assets in 2005. Such changes had an effect on our pension costs in 2007, 2006 and 2005 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 increased the pension plan discount rate in 2007 to 6.35 percent from 6.15 percent, which was used in 2006 for estimating the 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 2007, 2006 and 2005. The actual return on plan assets, net of fees, was a gain of $18.3 million (or 8.1 percent) for 2007, a gain of $25.2 million (or 12.6 percent) for 2006 and a gain of $11.3 million (or 6.1 percent) for 2005. 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%	$ –*	$ 1,130
Expected long-term return on plan assets	+0.5%	–*	(1,130)
Discount rate	-0.5%	21,297	2,254
Discount rate	+0.5%	(19,146)	(2,041)

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

We also have a SERP that provides additional pension benefits to our executive officers. 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.

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, 2007 by $1.6 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, 2007 by $1.4 million and the service and interest cost by $0.1 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 down. However, no assurance can be given for the ultimate outcome of any particular contingency.

LIQUIDITY AND CAPITAL RESOURCES

REVIEW OF CASH FLOW STATEMENT

Overall

During 2007, positive cash flows from operating activities of $251.6 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $205.8 million, debt maturities of $26.7 million, mandatory preferred stock redemptions of $26.3 million and dividends of $31.5 million. As cash flows from operating activities and other sources of cash inflows exceeded other funding requirements, our total debt decreased $31.6 million during 2007.

Operating Activities

Net cash provided by operating activities was $251.6 million for 2007 compared to $201.5 million for 2006. The overall increase was due in part to sale of Avista Energy's contracts and liquidation of Avista Energy's remaining net current assets. Net cash provided by working capital components was $80.9 million for 2007, compared to $16.5 million for 2006. 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 net 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).

The net cash provided during 2006 primarily reflects a decrease in:

- accounts receivable (representing net cash received from our customers),
- other current liabilities (primarily due to an increase in customer fund obligations at Advantage IQ), and
- cash deposits from counterparties (representing cash received as collateral funds from our counterparties).

This cash provided was partially offset by a decrease in:

- accounts payable (representing net cash paid to our vendors),
- other current assets (primarily due to an increase in funds held for customers at Advantage IQ), and
- cash deposits with counterparties (representing cash posted as collateral at Avista Energy).

Significant non-cash items included $19.6 million of power and natural gas cost amortizations, net of deferrals, for 2007, a decrease from $56.3 million for 2006 primarily due to an increase in deferrals of power costs as electric resource costs exceeded the amount included in base rates. Significant changes in non-cash items also included a $26.1 million change in energy commodity assets and liabilities, representing the change to an unrealized loss of $24.6 million on energy trading activities for 2007 as compared to an unrealized gain of $1.5 million for 2006. There was also a decrease in the benefit for deferred income taxes to a benefit of $7.4 million for 2007 from a benefit of $19.2 million for 2006. Income tax payments decreased to $29.4 million for 2007, compared to $63.4 million for 2006.

Investing Activities

Net cash used in investing activities was $186.6 million for 2007, an increase compared to $139.7 million for 2006. This was due to an increase in utility property capital expenditures in 2007 and other cash inflows during 2006, which included the receipt of $5.5 million from our sale of a claim against an affiliate of Enron Corporation related to the construction of Coyote Springs 2 and proceeds from asset sales of $25.7 million (including our investment in Rathdrum Power, LLC and a turbine at Avista Power). This was partially offset by a change in restricted cash. We liquidated $25.8 million of restricted cash in 2007 representing the return of cash collateralizing energy contracts at Avista Energy.

Financing Activities

Net cash used in financing activities was $81.5 million for 2007 compared to $59.4 million for 2006. 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. Cash dividends paid increased to $31.5 million (or 59.5 cents per share) for 2007 from $27.9 million (or 57 cents per share) for 2006. Debt maturities were $26.7 million for 2007 and we redeemed the remaining $26.3 million of our preferred stock outstanding as required.

During 2006, our short-term borrowings decreased $59.5 million, which primarily reflected a decrease in the amount of debt outstanding under our committed line of credit. In December 2006, we issued $150.0 million (proceeds of $149.8 million before underwriting discounts and other issuance costs) of 5.70 percent First Mortgage Bonds due in 2037. During 2006, debt redemptions and maturities were $199.0 million. In December 2006, we issued 3,162,500 shares of common stock through an underwriter and received net proceeds of $77.7 million. Total proceeds from other common stock issuances were $10.9 million for 2006.

OVERALL LIQUIDITY

With the completion of the sale of substantially all of Avista Energy's contracts and ongoing operations, 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. The primary source and use of operating cash flows for Avista Energy was revenues and costs from realized energy commodity transactions as well as cash collateral deposited to or held from counterparties. Significant operating cash outflows for Avista Energy also included other operating expenses and taxes.

On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations to Shell Energy. Proceeds from the sale of Avista Energy's net assets to Shell Energy and liquidation of Avista Energy's remaining net current assets (primarily receivables, restricted cash and deposits with counterparties) totaled $169 million. The majority of the proceeds from the transaction were deployed into our regulated utility operations. In September 2007, Avista Energy paid a $169 million cash dividend to Avista Capital and Avista Capital paid a $155 million cash dividend to Avista Corp. In December 2007, Avista Capital paid an additional $6 million dividend to Avista Corp.

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 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.

We will continue to 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. We filed a general rate case in Washington in April 2007. In October 2007, we reached a settlement in this general rate case that provides for rate increases averaging 9.4 percent for electric and 1.7 percent for natural gas, which was approved by the WUTC in December 2007. This is designed to increase annual electric revenues by $30.2 million and annual natural gas revenues by $3.3 million effective January 1, 2008. In February 2008, we reached a settlement in our Oregon general rate case, which is designed to increase annual revenues by $0.9 million on April 1, 2008 and $1.4 million on November 1, 2008. 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:

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

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.

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, 2007 and 2006 (dollars in thousands):

	December 31, 2007		December 31, 2006	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 427,344	21.6%	$ 26,605	1.3%
Short-term borrowings	–	–	4,000	0.2
Long-term debt to affiliated trusts	113,403	5.8	113,403	5.6
Long-term debt	521,489	26.4	949,854	46.7
Total debt	1,062,236	53.8	1,093,862	53.8
Preferred stock-cumulative (including current portion)	–	–	26,250	1.3
Total liabilities	1,062,236	53.8	1,120,112	55.1
Stockholders' equity	913,966	46.2	914,525	44.9
Total	$ 1,976,202	100.0%	$ 2,034,637	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 working capital, purchased power and natural gas costs, capital expenditures, dividends and other requirements. In September 2007, we redeemed the remaining $26.3 million of our outstanding preferred stock. Our stockholders' equity decreased $0.6 million during 2007 primarily due to dividends, the liability to subsidiary minority shareholders (Advantage IQ) and other comprehensive loss, mostly offset by net income.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities is expected to be the primary sources of funds for operating needs, dividends and capital expenditures for 2008. Borrowings under our $320.0 million committed line of credit may supplement these funds to the extent necessary.

We have long-term debt maturities of $318 million in 2008. Our forecasts indicate that we issue new debt securities to fund a significant portion of these requirements in 2008. In 2004, we entered into forward-starting interest rate swap agreements effectively locking in market fixed interest rates, which were relatively low compared to historical interest rates, for $125 million of our forecasted debt issuances in 2008.

In addition to the $318 million of debt maturities in 2008, we have $83.7 million of Pollution Control Bonds that are subject to remarketing on December 30, 2008. These bonds are included in the current portion of long-term debt because they are puttable at the option of the security holders on that date. If the bonds cannot be successfully remarketed on that date, we will be required to purchase the outstanding bonds. In addition, we have $25 million of Medium-Term Notes with a maturity date of June 2028 that are puttable at the option of the security holders in June 2008. These notes are included in the current portion of long-term debt.

We have a $320.0 million committed line of credit agreement with various banks with an expiration date of April 5, 2011. Under the agreement, we can request the issuance of up to $320.0 million in letters of credit. As of December 31, 2007, we did not have any borrowings outstanding under this committed line of credit, a decrease from $4.0 million as of December 31, 2006. As of December 31, 2007, there were $34.8 million in letters of credit outstanding, a decrease from $77.1 million as of December 31, 2006. 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.

Our committed line of credit agreement contains 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, 2007, we were in compliance with this covenant with a ratio of 2.70 to 1. The committed line of credit agreement also has a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 70 percent at the end of any fiscal quarter. As of December 31, 2007, we were in compliance with this covenant with a ratio of 53.8 percent. If the proposed change in organization to a holding company structure becomes effective, the committed line of credit agreement will remain at Avista Corp. (Avista Utilities). See "Note 26 of the Notes to Consolidated Financial Statements" for further information on the proposed change in organization to a holding company structure.

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, 2007, Avista Corp. and our subsidiaries were in compliance with all of the covenants of our financing agreements.

We are restricted under various agreements and our Restated Articles of Incorporation as to the additional preferred stock we can issue. As of December 31, 2007, we could issue $369.1 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 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, an on all indebtedness of prior rank. As of December 31, 2007, our property additions and retired bonds would have entitled us to issue $953.3 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2007, the net earnings test would limit the principal amount of additional bonds we could issue to $609.5 million. Thus, the decline in our "net earnings" (as defined in the Mortgage) in 2007 as compared to 2006 had a negative impact on the principal amount of additional First Mortgage Bonds we can issue. However, 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. As further discussed at "Note 26 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 related to the proposed implementation of our holding company structure. One of the conditions provides for the same utility equity components that are required in our January 2006 Washington general rate case. If we do not meet those targets, it could result in a reduction in base rates of 2 percent for each target in each of Washington and Idaho. We also entered into a settlement agreement in Washington related to our proposed holding company formation. In this settlement agreement, we committed to increase the utility equity component to 40 percent by June 30, 2008. However, the provision to reduce base rates by 2 percent does not apply if we fail to meet this target. If we fail to meet this Washington equity target at June 30, 2008, we will be required to use our most current actual equity ratio (in lieu of a hypothetical capital structure) in our next Washington general rate filing (subsequent to June 30, 2008). The utility equity component was approximately 45 percent as of December 31, 2007.

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. During the second half of 2008, we plan to begin issuing common stock under this sales agency agreement.

INTER-COMPANY DEBT; SUBORDINATION

As part of our on-going cash management practices and operations, from time to time Avista Corp. makes unsecured short-term loans to, and obtains borrowings from, its subsidiary, Avista Capital. In turn, Avista Capital from time to time makes unsecured short-term loans to, and obtains borrowings from, Avista Corp. and/or its subsidiaries. As of December 31, 2007, Avista Capital held a short-term subordinated note receivable from Avista Corp. in the principal amount of $2.2 million. In addition, Avista Capital from time to time guarantees the indebtedness and other obligations of its subsidiaries. The credit arrangements of Avista Capital's subsidiaries generally provide that any indebtedness owed by such entity to its corporate parent will be subordinated to the indebtedness outstanding under such credit arrangements.

The right of Avista Corp., as a shareholder, to receive assets of any of its direct or indirect subsidiaries upon the subsidiary's liquidation or reorganization (and the consequent right of the holders of debt securities and other creditors of Avista Corp. to participate in those assets) is subordinated to the claims against such assets of that subsidiary's creditors. As a result, the obligations of Avista Corp. to its debt security holders and other unrelated creditors are effectively subordinated in right of payment to all indebtedness and other liabilities and commitments (including trade payables and lease obligations) of Avista Corp.'s direct and indirect subsidiaries. Similarly, the obligations of Avista Capital to its creditors are effectively subordinated in right of payment to all indebtedness and other liabilities and commitments of its direct and indirect subsidiaries.

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 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment was to extend the termination date from March 20, 2007 to March 17, 2008. 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 $320.0 million committed line of credit. As of December 31, 2007, we had sold $85.0 million in accounts receivable under this revolving agreement. We expect to renew this facility before the March 17, 2008 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 $90.1 million as of December 31, 2007) 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 26, 2008:

	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, 2007, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. We contributed $15 million to the pension plan in both 2006 and 2007. We plan to contribute at least $15 million to the pension plan in 2008. Our total pension plan contributions were $84 million from 2002 through 2007.

The Pension Protection Act of 2006 (the Pension Act) was signed into law in August 2006. The Pension Act provides new funding rules for pension plans to improve the funded status of corporate defined benefit plans. The legislation is effective in 2008. The new funding rules could increase our minimum required cash contributions in excess of the $15 million we plan to contribute to the pension plan in 2008.

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 has generally been derived from our regulated utility operations (Avista Utilities) and Avista Energy.

With the completion of the sale of contracts and the liquidation of Avista Energy's remaining net current assets, almost all of Avista Energy's cash was distributed to Avista Capital through a dividend of $169 million in September 2007. Avista Capital then paid a cash dividend of $155 million to Avista Corp. In December 2007, Avista Capital paid an additional $6 million dividend to Avista Corp. As such, the majority of the proceeds from the Avista Energy transaction were deployed into 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, and to long-term debt contained in various indentures. Covenants under the 9.75 percent Senior Notes that mature on June 1, 2008 limit our ability to increase common stock cash dividends to no more than 5 percent over the previous quarter, unless certain conditions are met related to restricted payments. As of December 31, 2007, we met the conditions that would allow us to increase the common stock cash dividend in excess of 5 percent over the previous quarter.

On February 15, 2008, Avista Corp.'s Board of Directors declared a quarterly dividend of $0.165 per share on the Company's common stock, an increase of 10 percent or $0.015 per share, over the previous dividend.

As further discussed at "Note 26 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 45 percent as of December 31, 2007.

AVISTA UTILITIES OPERATIONS

Capital expenditures for our utility were $582.4 million for the years 2005 through 2007. We expect utility capital expenditures to be $200 million for 2008, and over $200 million in each of 2009 and 2010. 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. Scheduled long-term debt maturities are $318 million in 2008 and $35 million in 2010. In 2008, we will issue additional long-term debt to a fund a significant portion of these obligations. We locked in the interest rate on $125 million of long-term debt issuances during 2008 through forward-starting interest rate swap agreements.

We also have $83.7 million of Pollution Control Bonds that are subject to remarketing on December 30, 2008. These bonds are included in the current portion of long-term debt because they are puttable at the option of the security holders on that date. If the bonds cannot be successfully remarketed on that date, we will be required to purchase the outstanding bonds. In addition, we have $25 million of Secured Medium-Term Notes with a maturity date of June 2028 that are puttable at the option of the security holders in June 2008.

See "Notes 5, 14, 15, 16, 17, 20, 21 and 22 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.

We are close to completing the acquisition of a wind generation site. We expect to construct a 50 MW generation facility in 2010 or 2011 at an estimate cost of approximately $120 million. This amount is not included in our estimates of utility capital expenditures disclosed above. 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."

ADVANTAGE IQ OPERATIONS

Capital expenditures for Advantage IQ were $6.1 million for the years 2005 through 2007. We do not expect capital expenditures for the years 2008 through 2010 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, 2007, Advantage IQ had $0.4 million of debt outstanding related to capital leases.

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 upon 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, a liability of $14.0 million and a deferred income tax asset of $2.6 million were established in 2007 for the intrinsic value of stock options outstanding. An offsetting reduction was made to consolidated retained earnings of $11.4 million.

In February 2008, Advantage IQ entered into a $12.5 million three-year credit agreement with a bank. 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.

OTHER OPERATIONS

Capital expenditures for these companies were $2.2 million for the years 2005 through 2007. We do not expect capital expenditures for the years 2008 through 2010 for these companies to be significant to our consolidated cash flows and financial condition. As of December 31, 2007, these companies had $4.4 million of long-term debt outstanding.

CONTRACTUAL OBLIGATIONS

The following table provides a summary of our future contractual obligations as of December 31, 2007 (dollars in millions):

	2008	2009	2010	2011	2012	Thereafter
Avista Utilities:						
Long-term debt maturities (1)	$ 427	$ –	$ 35	$ –	$ 7	$ 475
Long-term debt to affiliated trusts	–	–	–	–	–	113
Interest payments on long-term debt (2)	58	45	44	42	41	755
Short-term borrowings (3)	–	–	–	–	–	–
Accounts receivable sales (4)	85	–	–	–	–	–
Energy purchase contracts (5)	316	233	188	134	126	1,032
Public Utility District contracts (5)	5	5	3	3	3	41
Operating lease obligations (6)	2	1	–	–	–	3
Other obligations (7)	15	15	15	15	15	167
Montana lease payments (8)	4	4	4	4	4	136
Information services contracts	15	15	15	14	14	–
Pension plan funding (9)	15	15	15	15	15	–
Avista Capital (consolidated):						
Long-term debt	–	–	–	–	–	4
Energy purchase contracts (10)	22	22	27	27	27	316
Operating lease obligations (6)	3	3	1	–	–	–
Total contractual obligations	$ 967	$ 358	$ 347	$ 254	$ 252	$ 3,042

(1) *In 2008, we will issue additional long-term debt to fund a significant portion of these obligations.*

(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, 2007.*

(3) *At December 31, 2007, we did not have any borrowings outstanding on our $320 million revolving line of credit.*

(4) *Represents $85 million outstanding under our revolving $85 million accounts receivable sales financing facility.*

(5) *Energy purchase contracts were entered into as part of the obligation to serve our retail natural gas and electric 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.*

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

(7) *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.*

(8) *Pursuant to the settlement of litigation (See "Montana Public School Trust Fund Lawsuit" in "Note 25 of the Notes to Consolidated Financial Statements" for further information), we agreed to make lease payments to the state of Montana in the initial amount of $4 million per year beginning in 2008, and continuing through calendar year 2016. Payments beyond 2008 will be adjusted each year by the Consumer Price Index, which has not been estimated as part of our obligation. On or before June 30, 2016, we will meet with the state of Montana to determine whether the annual lease payments remain consistent with the principles of law as applied to the facts and negotiate an adjusted lease payment for the remaining term of our FERC license for our hydroelectric facilities on the Clark Fork River (expires in 2046). Our obligation assumes no adjustment to our lease payments.*

(9) *Represents our estimated cash contributions to the pension plan through 2012. We cannot reasonably estimate pension plan contributions beyond 2012 at this time. The new funding rules under the Pension Act could increase our minimum required cash contributions in excess of the $15 million we plan to contribute to the pension plan in each year.*

(10) *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.*

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 resources can be critical to utilities as surplus power resources are absorbed by load growth. The Energy Policy Act of 1992 (1992 Energy Act) removed certain barriers to a competitive wholesale market. The 1992 Energy Act expanded the authority of the FERC to issue orders requiring electric utilities to:

- transmit power and energy to or for wholesale purchasers and sellers, and
- enlarge or construct additional transmission capacity for the purpose of providing these services.

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.

Our subsidiaries in the non-energy businesses, particularly Advantage IQ, are subject to competition for service to existing customers and as they develop products and services and enter new markets. Competition from other companies in these non-energy businesses may mean challenges for a company to be the first to market a new product or service to gain the advantage in market share. Other challenges for these businesses 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 the following risks including, but not limited to:

- 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,
- 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,
- competition, and
- availability of funding at a reasonable cost.

Also, like other utilities, our facilities and operations are exposed to natural disasters and terrorism risks or other malicious acts. 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 96 percent of normal in 2007. Our hydroelectric generation was below normal (based on a 70-year average) for six of the past eight years. We cannot determine if lower than normal hydroelectric generation will continue in future years. For 2008, we forecast hydroelectric generation to be slightly above normal. This 2008 forecast will change based upon precipitation, temperatures and other variables during the year. 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. 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, 2007, 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 25 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.

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:

- adequacy of North American production,
- level of imports,
- 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 the 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 the risk that a counterparty may 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 specific eligibility criteria to existing and prospective counterparties, and
- actively monitoring current credit exposures.

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. 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, 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.

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 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 subject to the risk of fluctuating interest rates in the normal course of business. 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 $83.7 million of Pollution Control Bonds with interest rates between 5.0 and 5.13 percent that are subject to remarketing on December 30, 2008. The remarketing of these bonds could result in higher interest rates on these securities. Additionally, amounts borrowed under our $320.0 million committed line of credit have a variable interest rate.

In 2004, we entered into forward-starting interest rate swap agreements, totaling $125.0 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 to fund maturing debt in 2008. 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 in accordance with SFAS No. 133. As of December 31, 2007, we had a derivative liability of $10.5 million and provided cash collateral of $4.1 million to the interest rate swap counterparties related to these interest rate swaps. We estimate that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2007 would decrease this derivative liability by $1.0 million, while a 10-basis-point decrease would increase the liability by $1.0 million.

Foreign Currency Risk

A significant portion of our utility natural gas supply is obtained from Canadian sources; however, most of those transactions are executed in U.S. dollars in order to mitigate foreign currency risk. We have foreign currency risk associated with certain short-term natural gas transactions and long-term Canadian transportation contracts. This risk has not had a material effect on our financial condition, results of operations or cash flows.

RISK MANAGEMENT

We use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have a risk management 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 and is overseen by the Audit Committee of the Company's Board of Directors. 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.

Our utility measures the monthly, quarterly and annual energy volume of the imbalance 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. Our utility buys and sells fuel for thermal generation facilities based on comparative power market prices and marginal costs of fueling and operating available generating facilities.

Load/resource imbalances within a rolling 18-month planning horizon are compared against established volumetric guidelines and management determines the timing and specific 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 utility 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 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.

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 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 are growing in importance in our utility service area. We anticipate moderate economic growth to continue throughout our 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 2.7 to 3.0 percent within our service area, we anticipate retail electric and natural gas load growth will average between 2.0 and 3.0 percent annually for the four year period 2008-2011. While the number of electric customers is growing, the average annual usage by each residential electric customer has stabilized. Commercial and industrial customers are expanding square footage and output at existing facilities, so the average customer usage is increasing. Natural gas sales growth has slowed as retail prices have risen 80 percent in the last five years. Population increases and business growth in our three-state service territory remains considerably 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 all 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.

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. 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 and Manitoba 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. By August 2008, the WCI partners are expected to complete the design of a market-based mechanism to help achieve this reduction goal.

The greenhouse gas bill passed into law in the state of Washington during 2007 places significant restrictions on greenhouse gas emissions from any new generation plants built in the state of Washington. Furthermore, utilities are prevented from entering into contracts to purchase energy produced by plants in other states that do not meet the same restrictions. Currently, the only type of thermal generating plants that meet these restrictions are combined-cycle natural gas-fired generation turbines. 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.

Initiative Measure 937 (I-937) was passed into law through the General Election in Washington in November 2006. I-937 requires certain investor-owned, cooperative, and government-owned electric utilities (including Avista Corp.) 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 conservation 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 September 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. In response to the new laws in the state of Washington as described above, the IRP eliminates 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.

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. The CCX allows participants to earn credits for reducing greenhouse gas emissions and trade the resulting financial instruments at market prices.

For other environmental issues and other contingencies see "Note 25 of the Notes to Consolidated Financial Statements."

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See "Management's Discussion and Analysis of Financial Condition and Results of Operations: – Business Risk and – Risk Management," "Management's Discussion and Analysis of Financial Condition and Results of Operations – Energy Marketing and Resource Management – Energy trading activities and positions," "Note 6 of the Notes to Consolidated Financial Statements" and "Note 21 of the Notes to Consolidated Financial Statements."

CONSOLIDATED STATEMENTS OF INCOME

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

	2007	2006 (as restated see Note 31)	2005 (as restated see Note 31)
Operating Revenues:			
Utility revenues	$ 1,288,363	$ 1,267,938	$ 1,161,317
Non-utility energy marketing and trading revenue	61,541	177,551	148,010
Other non-utility revenues	67,853	60,822	50,280
Total operating revenues	1,417,757	1,506,311	1,359,607
Operating Expenses:			
Utility operating expenses:			
Resource costs	780,998	751,646	669,596
Other operating expenses	198,778	187,457	181,755
Depreciation and amortization	86,091	81,904	80,914
Taxes other than income taxes	72,443	69,882	68,044
Non-utility operating expenses:			
Resource costs	68,676	144,137	145,994
Other operating expenses	67,783	66,546	59,653
Depreciation and amortization	4,559	5,179	5,997
Total operating expenses	1,279,328	1,306,751	1,211,953
Gain on sale of utility properties	–	–	4,093
Income from operations	138,429	199,560	151,747
Other Income (Expense):			
Interest expense	(79,142)	(89,051)	(86,512)
Interest expense to affiliated trusts	(7,298)	(7,116)	(6,202)
Capitalized interest	3,864	2,934	1,689
Regulatory disallowance of unamortized debt repurchase costs	(3,850)	–	–
Other income – net	10,806	8,600	10,030
Total other income (expense) – net	(75,620)	(84,633)	(80,995)
Income before income taxes	62,809	114,927	70,752
Income taxes	24,334	41,986	25,764
Net income	$ 38,475	$ 72,941	$ 44,988
Weighted-average common shares outstanding (thousands), basic	52,796	49,162	48,523
Weighted-average common shares outstanding (thousands), diluted	53,263	49,897	48,979
Total earnings per common share, basic (Note 23)	$ 0.73	$ 1.48	$ 0.93
Total earnings per common share, diluted (Note 23)	$ 0.72	$ 1.46	$ 0.92
Dividends paid per common share	$ 0.595	$ 0.570	$ 0.545

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

	2007	2006 (as restated see Note 31)	2005 (as restated see Note 31)
Net income	$ 38,475	$ 72,941	$ 44,988
Other Comprehensive Income (Loss):			
Foreign currency translation adjustment	1,010	(38)	268
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 $(1,874), $436 and $605, respectively	(3,480)	810	1,123
Reclassification adjustment for realized losses (gains) on interest rate swap agreements deferred as a regulatory (asset) liability – net of taxes of $1,308 and $(1,556)	–	2,430	(2,889)
Change in unfunded benefit obligation for pension plan – net of taxes of $1,642, $4,023 and $(1,444), respectively	3,050	7,472	(2,681)
Unrealized gains (losses) on derivative commodity instruments – net of taxes of $(324), $(555) and $1,693, respectively	(602)	(1,030)	3,145
Reclassification adjustment for realized gains on derivative commodity instruments included in net income – net of taxes of $(136), $(294) and $(898), respectively	(253)	(546)	(1,668)
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) and $(34)	–	(16)	(64)
Total other comprehensive income (loss)	(1,792)	9,162	(2,766)
Comprehensive income	$ 36,683	$ 82,103	$ 42,222

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation
As of December 31
Dollars in thousands

	2007	2006 (as restated see Note 31)
Assets:		
Current Assets:		
Cash and cash equivalents	$ 11,839	$ 28,242
Restricted cash	4,068	29,903
Accounts and notes receivable – less allowances of $42,582 and $42,360	105,440	286,150
Energy commodity derivative assets	–	343,726
Utility energy commodity derivative assets	12,078	10,828
Regulatory asset for utility derivatives	7,171	62,650
Funds held for customers	89,885	90,134
Deposits with counterparties	–	79,477
Materials and supplies, fuel stock and natural gas stored	34,985	42,425
Deferred income taxes	20,251	10,932
Income taxes receivable	30,025	28,402
Other current assets	16,443	19,405
Total current assets	332,185	1,032,274
Net Utility Property:		
Utility plant in service	3,131,916	2,938,456
Construction work in progress	100,106	103,226
Total	3,232,022	3,041,682
Less: Accumulated depreciation and amortization	880,680	826,645
Total net utility property	2,351,342	2,215,037
Other Property and Investments:		
Investment in exchange power – net	28,583	31,033
Non-current energy commodity derivative assets	–	313,300
Investment in affiliated trusts	13,403	13,403
Other property and investments – net	74,171	75,895
Total other property and investments	116,157	433,631
Deferred Charges:		
Regulatory assets for deferred income tax	117,461	105,935
Regulatory assets for pensions and other postretirement benefits	51,006	54,192
Other regulatory assets	43,004	31,752
Non-current utility energy commodity derivative assets	55,313	25,575
Power and natural gas deferrals	85,885	97,792
Unamortized debt expense	32,542	46,554
Other deferred charges	4,902	13,766
Total deferred charges	390,113	375,566
Total assets	$ 3,189,797	$ 4,056,508

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (CONTINUED)

Avista Corporation
As of December 31
Dollars in thousands

	2007	2006 (as restated see Note 31)
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Accounts payable	$ 117,546	$ 286,099
Energy commodity derivative liabilities	–	313,499
Customer fund obligations	89,885	90,134
Deposits from counterparties	12,510	41,493
Current portion of long-term debt	427,344	26,605
Preferred stock-cumulative ($100 stated value) (262,500 shares redeemed in 2007)	–	26,250
Short-term borrowings	–	4,000
Interest accrued	12,578	11,595
Utility energy commodity derivative liabilities	19,249	73,478
Other current liabilities	84,537	72,056
Total current liabilities	763,649	945,209
Long-term debt	521,489	949,854
Long-term debt to affiliated trusts	113,403	113,403
Other Non-Current Liabilities and Deferred Credits:		
Non-current energy commodity derivative liabilities	–	309,990
Regulatory liability for utility plant retirement costs	209,357	197,712
Non-current regulatory liability for utility derivatives	53,414	15,400
Pensions and other postretirement benefits	90,555	103,604
Deferred income taxes	440,918	459,756
Other non-current liabilities and deferred credits	83,046	47,055
Total other non-current liabilities and deferred credits	877,290	1,133,517
Total liabilities	2,275,831	3,141,983
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 52,909,013 and 52,514,326 shares outstanding	726,933	715,620
Accumulated other comprehensive loss	(19,608)	(17,816)
Retained earnings	206,641	216,721
Total stockholders' equity	913,966	914,525
Total liabilities and stockholders' equity	$ 3,189,797	$ 4,056,508

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

	2007	2006 (as restated see Note 31)	2005 (as restated see Note 31)
Operating Activities:			
Net income	$ 38,475	$ 72,941	$ 44,988
Non-cash items included in net income:			
Depreciation and amortization	90,650	87,083	86,911
Provision (benefit) for deferred income taxes	(7,369)	(19,212)	8,768
Power and natural gas cost amortizations, net of deferrals	19,630	56,327	9,630
Regulatory disallowance of unamortized debt repurchase costs	3,850	–	–
Amortization of debt expense	6,345	7,741	7,762
Write-offs and impairments of assets	2,290	–	1,001
Unrealized loss (gain) on energy commodity derivatives	24,594	(1,510)	38,126
Loss on sale of Avista Energy assets	4,254	–	–
Gain on sale of utility properties	–	–	(4,093)
Equity-related AFUDC	(4,736)	(2,429)	(1,389)
Other	(7,265)	(16,018)	(4,012)
Changes in working capital components:			
Accounts and notes receivable	180,488	219,071	(190,363)
Materials and supplies, fuel stock and natural gas stored	4,522	11,698	(10,642)
Deposits with counterparties	79,477	(20,123)	(28,687)
Other current assets	7,589	(46,477)	(19,801)
Accounts payable	(170,478)	(225,499)	189,115
Deposits from counterparties	(28,983)	27,769	7,709
Other current liabilities	8,308	50,104	(4,789)
Net cash provided by operating activities	251,641	201,466	130,234
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(205,811)	(161,266)	(215,341)
Proceeds from sale of utility property claim	–	5,484	–
Other capital expenditures	(3,280)	(3,819)	(4,044)
Purchase of auction rate investment securities	(130,000)	–	–
Sale of auction rate investment securities	130,000	–	–
Decrease (increase) in restricted cash	25,834	(4,269)	541
Changes in other property and investments	(3,784)	(1,980)	2,033
Repayments received on notes receivable	23	429	318
Proceeds from asset sales	441	25,706	17,211
Net cash used in investing activities	(186,577)	(139,715)	(199,282)

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (CONTINUED)

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

	2007	2006 (as restated see Note 31)	2005 (as restated see Note 31)
Financing Activities:			
Decrease in short-term borrowings	$ (4,000)	$ (59,494)	$ (5,023)
Proceeds from issuance of long-term debt	–	149,778	149,633
Redemption and maturity of long-term debt	(26,738)	(199,018)	(111,613)
Premiums paid for the redemption of long-term debt	–	(426)	(826)
Long-term debt and short-term borrowing issuance costs	(165)	(5,436)	(2,153)
Cash received (paid) in interest rate swap agreement	–	(3,738)	4,445
Redemption of preferred stock	(26,250)	(1,750)	(1,750)
Issuance of common stock	4,977	88,585	2,066
Equity issued by consolidated subsidiaries	2,568	–	–
Other equity transactions of consolidated subsidiaries	(408)	–	(1,688)
Cash dividends paid	(31,451)	(27,927)	(26,443)
Net cash provided by (used in) financing activities	(81,467)	(59,426)	6,648
Net increase (decrease) in cash and cash equivalents	(16,403)	2,325	(62,400)
Cash and cash equivalents at beginning of period	28,242	25,917	88,317
Cash and cash equivalents at end of period	$ 11,839	$ 28,242	$ 25,917
Supplemental Cash Flow Information:			
Cash paid during the period:			
Interest	$ 79,112	$ 95,475	$ 85,569
Income taxes	29,367	63,361	26,405
Non-cash financing and investing activities:			
Common stock issued to settle incentive compensation liability	–	3,238	–
Liability to subsidiary minority shareholders	13,978	–	–

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 Shares	Common Stock Amount	Note Receivable from Employee Stock Ownership Plan	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance as of December 31, 2004, as previously reported	48,471,511	$ 618,379	$ (495)	$ (20,533)	$ 155,854	$ 753,205
Cumulative effect of correction of an error (see Note 31)					(2,099)	(2,099)
Balance as of December 31, 2004 (as restated see Note 31)	48,471,511	$ 618,379	$ (495)	$ (20,533)	$ 153,755	$ 751,106
Net income (as restated see Note 31)					44,988	44,988
Equity compensation plan transactions		(5)			(788)	(793)
Issuance of common stock through Dividend Reinvestment Plan	121,628	2,224				2,224
Repayments of note receivable			495			495
Other comprehensive loss				(2,766)		(2,766)
Cash dividends paid (common stock)					(26,443)	(26,443)
Other					38	38
Balance as of December 31, 2005 (as restated see Note 31)	48,593,139	$ 620,598	$ –	$ (23,299)	$ 171,550	$ 768,849
Net income (as restated see Note 31)					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) (as restated see Note 31)				(3,679)		(3,679)
Cash dividends paid (common stock)					(27,927)	(27,927)
Other					415	415
Balance as of December 31, 2006 (as restated see Note 31)	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

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 business segments 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 29 for business segment information.

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

- 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,
- 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,
- competition, and
- availability of funding at a reasonable cost.

Also, like other utilities, the Company's facilities and operations are exposed to 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 8).

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 $16.1 million (net of $57.2 million of unbilled receivables sold) as of December 31, 2007 and $21.7 million (net of $51.6 million of unbilled receivables sold) as of December 31, 2006. See Note 5 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 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, $119.9 million in 2006 and $144.6 million in 2005.

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 2007, 2006 and 2005.

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 $51.0 million in 2007, $48.3 million in 2006 and $43.1 million in 2005.

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):

	2007	2006	2005
Interest income	$ 7,812	$ 9,366	$ 5,974
Interest on power and natural gas deferrals	4,369	6,497	7,429
Equity-related Allowance for Funds Used During Construction	4,736	2,429	1,389
Net gain (loss) on investments	445	(512)	156
Other expense	(6,837)	(9,358)	(6,228)
Other income	281	178	1,310
Total	$ 10,806	$ 8,600	$ 10,030

Stock-Based Compensation

Prior to January 1, 2006, the Company followed the disclosure only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, employee stock options were accounted for under Accounting Principle Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees." Stock options were granted at exercise prices not less than the fair value of common stock on the date of grant. Avista Corp. has not granted any stock options since 2003. Certain subsidiaries of Avista Corp. granted stock options to employees (exercisable into stock of the respective subsidiary) in more recent periods, which are not material to the consolidated financial statements. Under APB No. 25, no compensation expense was recognized pursuant to the Company's stock option plans. However, the Company recognized compensation expense related to performance-based share awards. The Company adopted SFAS No. 123R, "Share-Based Payment," on January 1, 2006, which resulted in changes to stock compensation expense recognition. See Note 24 for further information. The Company adopted SFAS No. 123R using the modified prospective method and, accordingly, the financial statements for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments.

If compensation expense for the Company's stock-based employee compensation plans were determined consistent with SFAS No. 123, net income and earnings per common share would be the following pro forma amounts for the year ended December 31, 2005 (prior to the adoption of SFAS No. 123R):

	2005
Net income (dollars in thousands):	
As reported	$ 44,988
Add: Total stock-based employee compensation expense included in net income, net of tax	2,211
Deduct: Total stock-based employee compensation expense determined under the fair value method for all awards, net of tax	(2,911)
Pro forma	$ 44,288
Basic and diluted earnings per common share:	
Basic as reported	$ 0.93
Diluted as reported	$ 0.92
Basic pro forma	$ 0.91
Diluted pro forma	$ 0.90

Accumulated Other Comprehensive Loss

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

	2007	2006
Foreign currency translation adjustment	$ –	$ 1,369
Unfunded benefit obligation for pensions and other postretirement benefit plans	(12,782)	(15,832)
Unrealized loss on interest rate swap agreements	(6,826)	(3,346)
Unrealized loss on derivative commodity instruments	–	(7)
Total accumulated other comprehensive loss	$ (19,608)	$ (17,816)

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 23 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 7 for further information related to cash deposits from counterparties.

Restricted Cash

Restricted cash consisted of the following as of December 31 (dollars in thousands):

	2007	2006
Bank deposits as collateral for letters of credit (Avista Energy)	$ –	$ 24,885
Bonus retention deposits held in trust (Avista Energy)	–	76
Deposits related to forward contracts (Avista Energy)	–	2,500
Deposits related to interest rate swap agreements (Avista Corp.)	4,068	2,442
Total	$ 4,068	$ 29,903

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):

	2007	2006	2005
Allowance as of the beginning of the year	$ 42,360	$ 44,634	$ 44,193
Additions expensed during the year	3,148	2,895	2,867
Net deductions	(2,926)	(5,169)	(2,426)
Allowance as of the end of the year	$ 42,582	$ 42,360	$ 44,634

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):

	2007	2006
Materials and supplies	$ 19,357	$ 16,050
Fuel stock	2,214	2,122
Natural gas stored	13,414	24,253
Total	$ 34,985	$ 42,425

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 9.11 percent in 2007 and 2006 and 9.72 percent for 2005. 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 unit rates for generation plants and composite rates for other utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. The rates for hydroelectric plants include annuity and interest components, in which the interest component is 9 percent. For utility operations, the ratio of depreciation provisions to average depreciable property was 2.89 percent in 2007, 2.89 percent in 2006 and 2.93 percent in 2005.

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

- electric thermal production – 28 years,
- hydroelectric production – 77 years,
- electric transmission – 45 years,
- electric distribution – 48 years, and
- natural gas distribution property – 37 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 10). The Company had estimated retirement costs included as a regulatory liability on the Consolidated Balance Sheets of $209.4 million as of December 31, 2007 and $197.7 million as of December 31, 2006. 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 and totaled $5.2 million (Other) as of December 31, 2007 and $6.2 million ($5.2 million in Other and $1.0 million in Energy Marketing and Resource Management) as of December 31, 2006.

The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2007 and determined that goodwill was not impaired at that time.

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 6 for further information),
- expenditures for demand side management programs,
- expenditures for conservation programs, 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,
- liabilities created when the Centralia Power Plant was sold,
- liabilities offsetting net utility energy commodity derivative assets (see Note 6 for further information), and
- the gain on the general office building sale/leaseback.

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, being recovered in current rates or earning a return (accruing interest), totaled $70.6 million as of December 31, 2007, of which the majority related to the regulatory asset for pensions and other postretirement benefits of $51.0 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, which 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. These costs are recovered through retail rates as a component of interest expense. Pursuant to a settlement agreement in its Washington general rate case in 2007, Avista Corp. agreed to write off $3.8 million of unamortized debt repurchase costs. See Note 4 for further details.

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 power supply costs incurred by Avista Utilities and the costs included in base retail rates. This difference in power supply costs primarily results from changes in:

- short-term wholesale market prices,
- 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 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 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 7.8 percent as of December 31, 2007. Total deferred power costs for Washington customers were $58.5 million as of December 31, 2007 and $70.2 million as of December 31, 2006.

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. As such, 50 percent of the annual power supply cost variance in this range is 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:

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%

Avista Utilities has a power cost adjustment (PCA) mechanism in Idaho that allows it to modify electric rates periodically 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 the annual rate adjustment provision. The 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, 2007. Total deferred power costs for Idaho customers were $21.2 million as of December 31, 2007 and $9.4 million as of December 31, 2006.

Natural Gas Cost Deferrals and Recovery Mechanisms

In the fall of each year, 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 were $2.4 million (an asset of $6.2 million and a liability of $3.8 million) as of December 31, 2007 and $18.3 million as of December 31, 2006.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2006, the Company adopted SFAS No. 123R, "Share-Based Payment," which supersedes APB No. 25 and SFAS No. 123 and their related implementation guidance. This statement established revised standards for the accounting for transactions in which the Company exchanges its equity instruments for goods or services with a primary focus on transactions in which the Company obtains employee services in share-based payment transactions. 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 implemented the provisions of this statement using the modified prospective method and, accordingly, financial statements for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. Under the modified prospective approach, SFAS 123R applied to all of the Company's unvested stock-based payment awards beginning January 1, 2006 and all prospective awards. In addition, SFAS No. 123R requires the Company to classify tax benefits resulting from tax deductions in excess of stock-based compensation expense recognized as a financing activity. This amount is not significant to cash flows and is included in the line item issuance of common stock on the Consolidated Statement of Cash Flows. See Note 24 for further information related to stock compensation plans.

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 12 for further information.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which provides enhanced guidance for using fair value to measure assets and liabilities. This statement also expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements. However, the statement does not require any new fair value measurements. This statement emphasizes that fair value is a market-based measurement and not an entity-specific measurement. Therefore a fair value measurement should be determined based on the assumptions that market participants would use in pricing an asset or liability. The statement establishes a fair value hierarchy that prioritizes the information used to develop those assumptions giving the highest priority to quoted prices in active markets and the lowest priority to unobservable data. The Company will be required to adopt SFAS No. 157 in 2008. The Company does not expect SFAS No. 157 to have a material impact on its financial condition and results of operations. However, the Company will have expanded disclosures with respect to fair value measurements.

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 February 2007, the FASB issued 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 will be required to adopt SFAS No. 159 in 2008. The Company does not plan to use the fair value option under SFAS No. 159 and as such does not expect SFAS No. 159 to impact its financial condition and results of operations.

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 from 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 is evaluating the impact SFAS No. 160 will have on its financial condition and results of operations.

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.

As consideration for the assets acquired (net of liabilities assumed), the purchase price paid by Shell Energy was calculated on the closing date as the sum of the following:

- the net trade book value of contracts acquired,
- the market value of the natural gas inventory, and
- the net book value of the tangible fixed assets acquired.

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). On July 2, 2007, Avista Energy received $34.4 million from Shell Energy based on the value of the net assets sold as of May 31, 2007. This amount was adjusted and Avista Energy paid Shell Energy $4.5 million on August 2, 2007 based on the determination of final market values and other closing adjustments as of June 30, 2007. 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.

Assets and liabilities excluded from the sale and retained or liquidated by Avista Energy include:

- cash,
- certain agreements, including electric transmission, natural gas transportation and a power purchase agreement, related to a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant), for periods after December 31, 2009 through 2026,
- storage rights at a natural gas facility located in Washington (Jackson Prairie) for periods after April 30, 2011,
- accounts receivable,
- accounts payable,
- tax obligations,
- cash deposits with and from counterparties,
- litigation matters (including matters related to western energy markets), and
- certain employment agreements and employee related obligations.

Certain assets of Avista Energy with a net book value of approximately $30 million have not been 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. The Company also expects that the power purchase agreement for the Lancaster Plant 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 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 25), 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. Avista Capital granted Shell Energy a security interest in 50 percent of Avista Capital's common shares of Advantage IQ as collateral for its Guaranty. The aggregate obligations secured by this security interest will in no event exceed $25 million. Avista Capital may substitute collateral, such as cash or letters of credit, in place of the security interest in Advantage IQ's common shares. This security interest in Advantage IQ's common shares will terminate in 18 months (December 31, 2008) except to the extent of claims actually made prior to expiration of the 18-month period. The Guaranty will terminate April 30, 2011 except with respect to claims made prior to termination.

As of February 25, 2008, there have not been any claims under the Indemnification Agreement or Guaranty.

Avista Energy made customary representations, warranties and covenants in the purchase and sale agreement. Avista Corp. and its subsidiaries agreed that for a period of 60 calendar months beginning on the closing of the transaction (June 30, 2007), neither Avista Corp. nor any of its subsidiaries will form or participate through ownership or any alliance, or internally, develop capabilities to replicate the business activities of Avista Energy within the region of the Western Electric Coordinating Council. This restriction has certain exceptions primarily related to any assets or contracts retained by Avista Energy and any current corporate activities outside of Avista Energy, including any resource optimization or associated trading or hedging activities of the character currently being conducted by Avista Utilities, an operating division of Avista Corp., in the ordinary course of its regulated utility business (see Note 6).

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.

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. 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 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment extended the termination date from March 20, 2007 to March 17, 2008. 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 $320.0 million committed line of credit (see Note 14). At each of December 31, 2007 and 2006, $85.0 million in accounts receivables were sold under this revolving agreement.

NOTE 6. ENERGY COMMODITY TRADING

The Company's energy-related businesses are exposed to risks relating to, but not limited to:

- changes in certain commodity prices, and
- counterparty performance.

Avista Utilities utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these exposures, and Avista Energy engaged in the trading of such instruments. The Company uses a variety of techniques to manage risks for their energy resources and wholesale energy market activities. The Company has a risk management policy and control procedures to manage these risks, both qualitative and quantitative. The Company's Risk Management Committee establishes the Company's risk management policy and control procedures and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other individuals and is overseen by the Audit Committee of the Company's Board of Directors.

Avista Utilities engages in an ongoing process of resource optimization, which involves the economic selection from available resources to serve Avista Utilities' load obligations and uses its existing 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:

- 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, estimates of streamflows, availability of generating units, historic and forward market information 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 rolling 18-month planning horizon are compared against established volumetric guidelines and management determines the timing and specific actions to manage the imbalances. Management also assesses available resource decisions and actions that are appropriate for longer-term planning periods.

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.

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. These contracts are entered into as part of Avista Utilities' management of its loads and resources as discussed above. In conjunction with the issuance 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 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):

	2007	2006
Current utility energy commodity derivative assets	$ 12,078	$ 10,828
Current utility energy commodity derivative liabilities	19,249	73,478
Net current regulatory asset	$ 7,171	$ 62,650
Non-current utility energy commodity derivative assets	$ 55,313	$ 25,575
Non-current utility energy commodity derivative liabilities	1,899	10,175
Net non-current regulatory liability	$ 53,414	$ 15,400

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

Avista Energy

As disclosed in Note 3, on June 30, 2007, Avista Energy and Avista Energy Canada sold substantially all of their contracts and ongoing operations. Avista Energy's results of operations are reflected in Avista Corp.'s consolidated financial statements for 2007, 2006 and 2005.

Avista Energy implemented hedge accounting in accordance with SFAS No. 133. Specific natural gas and electric trading derivative contracts were designated as hedging instruments in cash flow hedging relationships. With the completion of the sale of substantially all contracts on June 30, 2007, hedge accounting at Avista Energy was terminated and the balance of accumulated other comprehensive loss was reclassified to earnings as part of the loss on the transaction.

The change in the estimated fair value position of Avista Energy's energy commodity portfolio, net of reserves for credit and market risk for 2007 was an unrealized loss of $24.6 million and is included in the Consolidated Statements of Income in non-utility energy marketing and trading revenues. The change in the fair value position for 2006 was an unrealized gain of $1.5 million. In 2005, the unrealized loss was $38.1 million.

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 is 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. The Company manages the market risks inherent in their activities according to the risk management policy established by the Company's Risk Management Committee.

Credit Risk

Credit risk relates to the risk of loss 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 the risk that a counterparty may 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 specific eligibility criteria to existing and prospective counterparties, and
- actively monitoring current credit exposures.

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.

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, 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 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 7. CASH DEPOSITS WITH AND FROM COUNTERPARTIES

Cash deposits from counterparties totaled $12.5 million as of December 31, 2007 and $41.5 million as of December 31, 2006. These funds were held by Avista Utilities and Avista Energy (2006 only) 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. Cash deposited with counterparties at Avista Energy totaled $79.5 million as of December 31, 2006.

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.

NOTE 8. 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 $329.6 million and accumulated depreciation was $197.7 million as of December 31, 2007.

NOTE 9. 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):

	2007	2006
Avista Utilities:		
Electric production	$ 1,010,997	$ 991,794
Electric transmission	443,833	383,824
Electric distribution	881,923	832,094
Construction work-in-progress (CWIP) and other	155,317	162,071
Electric total	2,492,070	2,369,783
Natural gas underground storage	19,082	18,672
Natural gas distribution	547,153	502,237
CWIP and other	58,344	52,646
Natural gas total	624,579	573,555
Common plant (including CWIP)	115,373	98,344
Total Avista Utilities	3,232,022	3,041,682
Energy Marketing and Resource Management [1]	15,101	18,157
Advantage IQ [1]	19,656	17,355
Other [1]	29,761	34,711
Total	$ 3,296,540	$ 3,111,905

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

NOTE 10. 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):

	2007	2006	2005
Asset retirement obligation at beginning of year	$ 4,810	$ 4,529	$ 1,191
New liability recognized	–	–	3,243
Liability adjustment due to revision in estimated cash flows	(1,063)	–	–
Liability settled	(71)	(51)	(28)
Accretion expense	314	332	123
Asset retirement obligation at end of year	$ 3,990	$ 4,810	$ 4,529

NOTE 11. 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 and Avista Energy. 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 $15 million in cash to the pension plan in each of 2007, 2006 and 2005. The Company expects to contribute at least $15 million to the pension plan in 2008.

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 $15.2 million in 2008, $15.5 million in 2009, $16.2 million in 2010, $16.7 million in 2011 and $17.8 million in 2012. For the ensuing five years (2013 through 2017), the Company expects that benefit payments under the pension plan and the SERP will total $110.0 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 the Finance Committee to ensure 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 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, 2007 and 2006.

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 2006, the form of payment election assumption was analyzed based upon historical trends and future projections. The Company revised the form of payment election to assume that 5 percent of retirees and 50 percent of vested terminated participants will elect a lump sum payment, based upon the analysis. The form of payment election assumption previously assumed that 50 percent of retirees and vested terminated participants would elect a lump sum payment. The change resulted in an increase of $13.2 million to the pension benefit obligation as of December 31, 2006. The change also increases 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 expects that benefit payments under the postretirement benefit plan will be $3.1 million in 2008, $3.0 million in 2009, $2.9 million in 2010, $2.8 million in 2011 and $2.7 million in 2012. For the ensuing five years (2013 through 2017), the Company expects that benefit payments under the postretirement benefit plan will total $12.3 million. The Company expects to contribute $3.1 million to the postretirement benefit plan in 2008, representing expected benefit payments to be paid during the year.

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. As disclosed in Note 31, the Company restated prior financial statements to recognize the liability and costs of this plan. 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.

The Company uses a December 31 measurement date for its pension and postretirement plans. The following table sets forth the pension and other postretirement plan disclosures as of December 31, 2007 and 2006 and the components of net periodic benefit costs for the years ended December 31, 2007, 2006 and 2005 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2007	2006	2007	2006
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 315,691	$ 301,746	$ 33,632	$ 32,710
Service cost	10,694	9,963	672	639
Interest cost	19,161	17,158	2,159	1,956
Plan amendment	–	–	(1,601)	–
Actuarial loss (gain)	(5,245)	2,524	2,612	1,914
Transfer of accrued vacation	–	–	585	–
Benefits paid	(16,912)	(15,521)	(3,707)	(3,557)
Expenses paid	(299)	(179)	–	(30)
Benefit obligation as of end of year	$ 323,090	$ 315,691	$ 34,352	$ 33,632
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 225,079	$ 199,163	$ 20,878	$ 18,378
Actual return on plan assets	18,799	25,737	1,840	2,530
Employer contributions	15,000	15,000	–	–
Benefits paid	(16,018)	(14,642)	–	–
Expenses paid	(299)	(179)	–	(30)
Fair value of plan assets as of end of year	$ 242,561	$ 225,079	$ 22,718	$ 20,878
Funded status	$ (80,529)	$ (90,612)	$ (11,634)	$ (12,754)
Unrecognized net actuarial loss	62,174	69,679	4,472	2,084
Unrecognized prior service cost	3,098	3,751	(1,600)	–
Unrecognized net transition obligation	–	–	2,526	3,031
Accrued benefit cost	(15,257)	(17,182)	(6,236)	(7,639)
Additional liability	(65,272)	(73,430)	(5,398)	(5,115)
Accrued benefit liability	$ (80,529)	$ (90,612)	$ (11,634)	$ (12,754)
Accumulated pension benefit obligation	$ 275,159	$ 264,647	–	–
Accumulated postretirement benefit obligation:				
For retirees			$ 18,572	$ 20,351
For fully eligible employees			$ 9,675	$ 7,169
For other participants			$ 6,105	$ 6,112
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ –	$ –	$ 1,642	$ 1,970
Unrecognized prior service cost	2,013	2,438	(1,040)	–
Unrecognized net of net actuarial loss	40,414	45,291	2,907	1,358
Total	42,427	47,729	3,509	3,328
Less regulatory asset	(28,560)	(31,992)	(4,594)	(3,233)
Accumulated other comprehensive loss (income)	$ 13,867	$ 15,737	$ (1,085)	$ 95
Weighted-average asset allocations as of December 31:				
Equity securities	49%	53%	62%	64%
Debt securities	31%	28%	38%	33%
Real estate	6%	5%	–	–
Other	14%	14%	–	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%	–	–
Other	10-22%	10-22%	–	–

	Pension Benefits 2007	Pension Benefits 2006	Other Post-retirement Benefits 2007	Other Post-retirement Benefits 2006
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	6.34%	6.15%	6.20%	6.15%
Discount rate for annual expense	6.15%	5.75%	6.15%	5.75%
Expected long-term return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.66%	4.84%		
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			2012	2011
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			2011	2010

	Pension Benefits 2007	Pension Benefits 2006	Pension Benefits 2005	Other Post-retirement Benefits 2007	Other Post-retirement Benefits 2006	Other Post-retirement Benefits 2005
Components of net periodic benefit cost:						
Service cost	$ 10,694	$ 9,963	$ 9,480	$ 672	$ 639	$ 654
Interest cost	19,161	17,158	16,228	2,159	1,956	1,839
Expected return on plan assets	(19,217)	(16,997)	(15,917)	(1,775)	(1,562)	(1,368)
Transition (asset)/obligation recognition	–	–	(499)	505	505	505
Amortization of prior service cost	653	653	654	–	–	–
Net loss recognition	2,978	3,772	3,442	193	90	–
Net periodic benefit cost	$ 14,269	$ 14,549	$ 13,388	$ 1,754	$ 1,628	$ 1,630

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, 2007 by $1.6 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, 2007 by $1.4 million and the service and interest cost by $0.1 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 $5.1 million in 2007, $4.7 million in 2006 and $4.4 million in 2005.

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, 2007 and 2006, there were deferred compensation assets of $12.1 million and $12.6 million included in other property and investments-net and corresponding deferred compensation liabilities of $12.1 million and $12.6 million included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets.

NOTE 12. ACCOUNTING FOR INCOME TAXES

Income tax expense consisted of the following for the years ended December 31, 2007 (dollars in thousands):

	2007	2006	2005
Taxes currently provided	$ 31,703	$ 61,198	$ 16,996
Deferred income taxes	(7,369)	(19,212)	8,768
Total income tax expense	$ 24,334	$ 41,986	$ 25,764

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2007, 2006 and 2005) 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):

	2007	2006	2005
Federal income taxes at statutory rates	$ 21,983	$ 40,224	$ 24,763
Increase (decrease) in tax resulting from:			
Tax effect of regulatory treatment of utility plant differences	4,526	4,342	2,870
State income tax expense	732	1,853	1,139
Preferred dividends	479	670	713
Settlement of prior year tax returns and adjustment of tax reserves	1,019	(1,437)	42
Manufacturing deduction	(1,738)	(735)	(385)
Kettle Falls tax credit	(2,645)	(3,201)	(2,891)
Other-net	(22)	270	(487)
Total income tax expense	$ 24,334	$ 41,986	$ 25,764

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):

	2007	2006
Deferred income tax assets:		
Allowance for doubtful accounts	$ 14,791	$ 14,911
Reserves not currently deductible	8,026	9,581
Foreign tax credit	–	4,088
Contributions in aid of construction	12,967	11,778
Deferred compensation	4,110	5,051
Unfunded benefit obligation	26,888	31,651
Utility energy commodity derivatives	25,514	34,669
Interest rate swaps	2,451	1,801
Tax credits	7,378	–
Other	17,282	10,087
Total deferred income tax assets	$ 119,407	$ 123,617
Deferred income tax liabilities:		
Differences between book and tax basis of utility plant	413,231	417,255
Power and natural gas deferrals	29,115	34,454
Regulatory asset for pensions and other postretirement benefits	17,852	18,967
Unrealized energy commodity gains	–	12,154
Power exchange contract	31,014	34,101
Utility energy commodity derivatives	25,514	34,669
Demand side management programs	5,943	4,477
Loss on reacquired debt	6,103	8,869
Foreign subsidiary income	–	4,088
Other	11,302	3,407
Total deferred income tax liabilities	540,074	572,441
Net deferred income tax liability	$ 420,667	$ 448,824

Net current deferred income tax assets were $20.3 million as of December 31, 2007 and $10.9 million as of December 31, 2006. Net non-current deferred tax liabilities were $440.9 million as of December 31, 2007 and $459.8 million as of December 31, 2006.

As of December 31, 2007, the Company had $7.4 million of Idaho and Oregon investment tax credit carryforwards. Investment tax credits expire from 2014 to 2020. The Company recognizes the effect of state investment 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 examined the Company's 2001, 2002 and 2003 federal income tax returns. Despite those tax years still remaining open, all issues were resolved with the exception of the timing for the deductions of certain indirect overhead costs. The IRS is currently conducting an examination of the Company's 2004 and 2005 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.

Due to the revenue ruling and related regulations, the IRS has 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 believes 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 on April 19, 2006. The Company's appeal is being reviewed by the IRS Appeals Division. The Company repaid a portion of the previous tax deductions through tax payments in 2005 and 2006. There can be no assurance that the Company's position will prevail. However, it is not expected to have a significant effect on the Company's net income.

The Company estimates that its liability for unrecognized tax benefits is $22.6 million at each of January 1, 2007 and December 31, 2007. With the adoption of FIN 48, this amount was reclassified from deferred income taxes to liability for unrecognized tax benefits. This liability primarily relates to the indirect overhead expenses described above, and the amount of this liability is included as other non-current liabilities and deferred credits on the Consolidated Balance Sheet as of December 31, 2007. The liability for unrecognized tax benefits would not affect the tax rate if recognized in 2007, as any adjustment to this tax item would be offset by an adjustment to current income tax expense. The liability for interest expense for unrecognized tax benefits as of January 1, 2007 was not material due to net operating loss and tax credit carryovers. The change in the liability for interest expense during 2007 was not material. The Company has not accrued any penalties. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

The Company had net regulatory assets of $117.5 million at December 31, 2007 and $105.9 million at December 31, 2006 related to the probable recovery of certain deferred tax liabilities from customers through future rates.

NOTE 13. 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 $733.5 million in 2007, $682.5 million in 2006 and $652.2 million in 2005.

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):

	2008	2009	2010	2011	2012	Thereafter	Total
Power resources	$ 125,265	$ 120,493	$ 110,608	$ 78,163	$ 74,162	$ 395,936	$ 904,627
Natural gas resources	190,545	112,215	77,058	56,075	52,034	636,375	1,124,302
Total	$ 315,810	$ 232,708	$ 187,666	$ 134,238	$ 126,196	$ 1,032,311	$ 2,028,929

All of the energy purchase contracts were entered into as part of Avista Utilities' obligation to serve its retail natural gas and electric 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):

	2008	2009	2010	2011	2012	Thereafter	Total
Contractual obligations	$ 15,207	$ 15,234	$ 15,262	$ 15,291	$ 15,322	$ 167,144	$ 243,460

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 $18.0 million in 2007, $13.1 million in 2006 and $9.0 million in 2005. Information as of December 31, 2007 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	$ 2,181	$ 1,007	$ 1,796	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,891	795	4,506	2018
Grant County PUD:						
Priest Rapids Project	3.3%	55,000	9,534	882	10,064	2055
Wanapum Project	8.2%	75,000	4,430	2,949	18,526	2055
Totals		197,000	$ 18,036	$ 5,633	$ 34,892	

(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 2007. Debt service costs are included in annual costs.*

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

	2008	2009	2010	2011	2012	Thereafter	Total
Minimum payments	$ 4,531	$ 4,554	$ 3,280	$ 3,210	$ 2,742	$ 41,265	$ 59,582

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):

	2008	2009	2010	2011	2012	Thereafter	Total
Energy purchase contracts	$ 21,700	$ 21,700	$ 26,728	$ 26,728	$ 26,530	$ 316,025	$ 439,411

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 14. 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 $34.8 million as of December 31, 2007 and $77.1 million as of December 31, 2006. 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.

The committed line of credit agreement contains 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, 2007, the Company was in compliance with this covenant with a ratio of 2.70 to 1. The committed line of credit agreement also has 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 the end of any fiscal quarter. As of December 31, 2007, the Company was in compliance with this covenant with a ratio of 53.8 percent. If the proposed change in organization becomes effective, the committed line of credit will remain at Avista Corp.

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):

	2007	2006	2005
Balance outstanding at end of period	$ –	$ 4,000	$ 63,000
Maximum balance outstanding during the period	48,000	77,000	167,000
Average balance outstanding during the period	6,833	16,740	61,181
Average interest rate during the period	7.91%	6.07%	4.45%
Average interest rate at end of period	– %	8.25%	5.48%

NOTE 15. 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	2007	2006
2007	Secured Medium-Term Notes	5.99%	$ –	$ 13,850
2008	Secured Medium-Term Notes	6.06%-6.95%	45,000	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
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 (1)	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (2)	5.00%	66,700	66,700
2034	Secured Pollution Control Bonds (2)	5.13%	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		666,700	680,550
2007	Unsecured Medium-Term Notes	7.90%-7.94%	–	12,000
2008	Unsecured Senior Notes	9.75%	272,860	272,860
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Total unsecured long-term debt		276,960	288,960
	Other long-term debt and capital leases		5,169	7,364
	Interest rate swaps		1,083	1,037
	Unamortized debt discount		(1,079)	(1,452)
	Total		948,833	976,459
	Current portion of long-term debt		(427,344)	(26,605)
	Total long-term debt		$ 521,489	$ 949,854

(1) *These Secured Medium-Term Notes with a maturity date of June 2028 are puttable at the option of the security holders in June 2008. These notes are included in the current portion of long-term debt.*

(2) *These Secured Pollution Control Bonds are subject to remarketing on December 30, 2008. These bonds are included in the current portion of long-term debt because they are puttable at the option of the security holders on that date. If the bonds cannot be successfully remarketed on that date, the Company will be required to purchase the outstanding bonds.*

The following table details future long-term debt maturities (2008 maturities include amounts discussed at (1) and (2) above), including long-term debt to affiliated trusts (see Note 16) (dollars in thousands):

Year	2008	2009	2010	2011	2012	Thereafter	Total
Debt maturities	$ 426,560	$ –	$ 35,000	$ –	$ 7,000	$ 588,503	$ 1,057,063

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 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, an on all indebtedness of prior rank. As of December 31, 2007, property additions and retired bonds would have entitled the Company to issue $953.3 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2007, the net earnings test would limit the principal amount of additional bonds the Company could issue to $609.5 million.

See Note 14 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its $320.0 million committed line of credit.

NOTE 16. 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 2007 ranged from 5.999 percent to 6.455 percent. As of December 31, 2007, the annual distribution rate was 5.999 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; however, this is limited by an agreement under the Company's 9.75 percent Senior Notes that mature on June 1, 2008. 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 17. 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 hedges against fluctuations in future cash flows associated with changes in interest rates in accordance with SFAS No. 133.

In 2005, the Company cash settled an interest rate swap and received $4.4 million. In December 2006, Avista Corp. cash settled an interest rate swap agreement and paid $3.7 million. These settlements were deferred as regulatory items (part of long-term debt) and will be amortized over the remaining terms of the interest rate swap agreements (forecasted interest payments) in accordance with regulatory accounting practices.

Under the terms of the two outstanding interest rate swap agreements (totaling $125.0 million) as of December 31, 2007, 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 2008. As of December 31, 2007, Avista Corp. had a long-term derivative liability of $10.5 million and a net unrealized loss of $6.8 million recorded as accumulated other comprehensive loss on the Consolidated Balance Sheets. The interest rate swap agreements provide for mandatory cash settlement of these contracts in 2009. The amount included in accumulated other comprehensive income or loss at the cash settlement date will be reclassified to a regulatory asset or liability (part of long-term debt) in accordance with regulatory accounting practices under SFAS No. 71. This regulatory asset or liability will be amortized as a component of interest expense over the life of the forecasted interest payments.

NOTE 18. 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 2007, $5.4 million in 2006 and $7.2 million in 2005.

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2007 were as follows (dollars in thousands):

Year ending December 31:	2008	2009	2010	2011	2012	Thereafter	Total
Minimum payments required	$ 4,160	$ 3,922	$ 1,685	$ 201	$ 117	$ 2,798	$ 12,883

NOTE 19. 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.

Avista Power, through its equity investment in Rathdrum Power, LLC (RP LLC), was a 49 percent owner of the Lancaster Plant, which commenced commercial operation in September 2001. In October 2006, Avista Power completed the sale of its investment in RP LLC for close to book value. 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 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 25), 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. Avista Capital granted Shell Energy a security interest in 50 percent of Avista Capital's common shares of Advantage IQ as collateral for its Guaranty. The aggregate obligations secured by this security interest will in no event exceed $25 million. Avista Capital may substitute collateral, such as cash or letters of credit, in place of the security interest in Advantage IQ's common shares. This security interest in Advantage IQ's common shares will terminate in 18 months (December 31, 2008) except to the extent of claims actually made prior to expiration of the 18-month period. The Guaranty will terminate April 30, 2011 except with respect to claims made prior to termination.

NOTE 20. PREFERRED STOCK-CUMULATIVE (SUBJECT TO MANDATORY REDEMPTION)

The Company has 10 million authorized shares of $6.95 Series K preferred stock. In September 2007, the Company redeemed the 262,500 remaining outstanding shares of this preferred stock for $26.25 million. In each of September 2006 and 2005, the Company made mandatory redemptions of 17,500 shares of preferred stock for $1.75 million.

NOTE 21. FAIR VALUE OF FINANCIAL INSTRUMENTS

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. Energy commodity derivative assets and liabilities, as well as derivatives related to interest rate swap agreements, are reported at estimated fair value on the Consolidated Balance Sheets.

The following table sets forth the estimated fair value and carrying value of the Company's long-term debt (including current portion, but excluding capital leases), long-term debt to affiliated trusts and preferred stock subject to mandatory redemption as of December 31, 2007 and 2006 (dollars in thousands):

	2007		2006	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt	$ 943,660	$ 969,899	$ 969,510	$ 976,548
Long-term debt to affiliated trusts	113,403	109,109	113,403	110,147
Preferred stock	–	–	26,250	26,622

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

NOTE 22. 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 26), 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 Dividend Reinvestment and Stock Purchase 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 2007, 2006 and 2005 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 and long-term debt contained in the Company's Articles of Incorporation and various mortgage indentures. Covenants under the Company's 9.75 percent Senior Notes that mature in 2008 limit the Company's ability to increase its common stock cash dividend to no more than 5 percent over the previous quarter, unless certain conditions are met related to restricted payments. As of December 31, 2007, the Company met the conditions that would allow it to increase the common stock cash dividend in excess of 5 percent over the previous quarter.

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. As of February 25, 2008, the Company has not issued any shares under the sales agency agreement.

NOTE 23. 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):

	2007	2006	2005
Numerator:			
Net income	$ 38,475	$ 72,941	$ 44,988
Subsidiary earnings adjustment for dilutive securities	(349)	–	–
Adjusted net income for computation of diluted earnings per common share	$ 38,126	$ 72,941	$ 44,988
Denominator:			
Weighted-average number of common shares outstanding-basic	52,796	49,162	48,523
Effect of dilutive securities:			
Contingent stock awards	168	371	198
Stock options	299	364	258
Weighted-average number of common shares outstanding-diluted	53,263	49,897	48,979
Total earnings per common share, basic	$ 0.73	$ 1.48	$ 0.93
Total earnings per common share, diluted	$ 0.72	$ 1.46	$ 0.92

Total stock options outstanding that were not included in the calculation of diluted earnings per common share were 303,950 for 2007, 26,200 for 2006 and 695,500 for 2005. 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. In addition, contingent stock awards of 318,900 were outstanding as of December 31, 2005, which were not included in basic or diluted shares because the performance conditions were not satisfied.

NOTE 24. 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, 2007, 0.9 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, 2007, 1.7 million shares were remaining for grant under this plan.

Stock Compensation

Prior to January 1, 2006, the Company accounted for stock based compensation using APB No. 25, which required the recognition of compensation expense on the excess, if any, of the market price of the stock at the date of grant over the exercise price of the option. As the exercise price for options granted under the 1998 and 2000 Plans was equal to the market price at the date of grant, there was no compensation expense recorded by the Company. However, the Company recognized compensation expense related to performance-based share awards. For periods presented prior to January 1, 2006, the Company is required to disclose pro forma net income and earnings per common share as if the Company had adopted the fair value method of accounting for 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. The Company recorded stock-based compensation expense of $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 $1.0 million for 2007 and $1.5 million for 2006.

Stock Options

The fair value of stock option awards was calculated using the Black Scholes option pricing model. This model requires the use of subjective assumptions, including stock price volatility, dividend yield, risk-free interest rate and expected time to exercise. See Note 1 for disclosure of pro forma net income and earnings per common share for 2005.

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

	2007	2006	2005
Number of shares under stock options:			
Options outstanding at beginning of year	1,541,045	2,095,211	2,332,198
Options granted	–	–	–
Options exercised	(123,134)	(504,452)	(192,377)
Options canceled	(6,000)	(49,714)	(44,610)
Options outstanding at end of year	1,411,911	1,541,045	2,095,211
Options exercisable at end of year	1,411,911	1,541,045	1,968,629
Weighted average exercise price:			
Options granted	$ –	$ –	$ –
Options exercised	$ 15.14	$ 16.12	$ 13.50
Options canceled	$ 26.59	$ 20.77	$ 20.42
Options outstanding at end of year	$ 15.38	$ 15.41	$ 15.68
Options exercisable at end of year	$ 15.38	$ 15.41	$ 16.03
Intrinsic value of options exercised (in thousands)	$ 1,022	$ 3,520	$ 956
Intrinsic value of options outstanding (in thousands)	$ 8,697	$ 15,256	$ 4,253

Information for options outstanding and exercisable as of December 31, 2007 was as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17-$11.68	357,560	$ 10.29	4.7
$11.69-$14.61	372,775	11.82	3.8
$14.62-$17.53	243,501	17.04	2.2
$17.54-$20.45	134,125	18.76	1.1
$20.46-$26.29	283,750	22.56	2.7
$26.30-$28.47	20,200	27.63	2.2
Total	1,411,911	$ 15.38	3.3

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

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

	2007	2006
Unvested shares at beginning of year	36,180	–
Shares granted	31,860	36,260
Shares cancelled	(19,936)	(80)
Shares vested	(19,967)	–
Unvested shares at end of year	28,137	36,180
Weighted average fair value at grant date	$ 25.60	$ 21.32
Unrecognized compensation expense at end of year (in thousands)	$ 517	$ 439
Intrinsic value, unvested shares at end of year (in thousands)	$ 606	$ 916
Intrinsic value, shares vested during the year (in thousands)	$ 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:

	2007	2006	2005
Risk-free interest rate	4.8%	4.6%	3.4%
Expected life, in years	3	3	3
Expected volatility	19.4%	21.9%	34.1%
Dividend yield	2.5%	2.9%	3.0%
Weighted average grant date fair value (per share)	$ 18.71	$ 18.08	$ 16.70

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

The following summarizes performance share activity:

	2007	2006	2005
Opening balance of unvested performance shares	300,406	318,331	308,145
Performance shares granted	114,640	138,710	163,600
Performance shares canceled	(45,632)	(1,404)	(500)
Performance shares vested	(161,573)	(155,231)	(152,914)
Ending balance of unvested performance shares	207,841	300,406	318,331
Intrinsic value of unvested performance shares (in thousands)	$ 4,477	$ 7,603	$ 5,638
Unrecognized compensation expense (in thousands)	$ 2,058	$ 2,400	$ –

The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2007 was 1.4 years. Unrecognized compensation expense as of December 31, 2007 will be recognized during 2008 and 2009.

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

	2007	2006	2005
Performance shares vested	161,573	155,231	152,914
Impact of market condition on shares vested	(56,551)	34,151	30,583
Shares of common stock earned	105,022	189,382	183,497
Intrinsic value of common stock earned (in thousands)	$ 2,262	$ 4,793	$ 3,250

In 2007, 2006 and 2005, the number of performance shares vested was adjusted by (35) percent, 22 percent and 20 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, 2007 and 2006, the Company had recognized compensation expense and a liability of $0.4 million and $0.7 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 $0.7 million as of December 31, 2007, which will be expensed during 2008 through 2011.

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 upon 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, a liability of $14.0 million and a deferred income tax asset of $2.6 million were established in 2007 for the intrinsic value of stock options outstanding. An offsetting reduction was made to consolidated retained earnings of $11.4 million.

NOTE 25. 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.

Class Action Securities Litigation

On June 1, 2007, Avista Corp. entered into a settlement agreement with respect to a class action lawsuit filed against Avista Corp., Thomas M. Matthews, a former Chairman of the Board, President and Chief Executive Officer of Avista Corp., Gary G. Ely, a former Chairman of the Board, President and Chief Executive Officer of Avista Corp., and Jon E. Eliassen, a former Senior Vice President and Chief Financial Officer of Avista Corp. The settlement agreement was filed in the United States District Court for the Eastern District of Washington (the Court) on June 4, 2007.

The lawsuit commenced with the filing of several class action complaints in the Court in September through November 2002. These complaints were subsequently consolidated and ultimately dismissed by the Court in October 2005. The order to dismiss was issued without prejudice, however, which allowed the plaintiffs to file an amended complaint. The amended class action complaint was filed on November 10, 2005 and asserted claims on behalf of all persons who purchased, converted, exchanged or otherwise acquired the Company's common stock during the period between November 23, 1999 and August 13, 2002.

The settlement agreement provides for certification of the plaintiff class and a full release by the class and dismissal with prejudice of all claims against Avista Corp. in consideration of payment of $9.5 million into a settlement fund. The settlement payment and litigation defense costs will be paid by Avista Corp.'s insurance company with the exception of the Company's $1 million self-insured retention. The settlement agreement further provides that the individual defendants Matthews, Ely and Eliassen will be dismissed from the lawsuit.

The Company vigorously contested this lawsuit since it commenced on September 27, 2002. The Company denied, and continues to deny in their entirety, the allegations of wrongdoing in the lawsuit, including the allegations that Avista Corp. made any false or misleading statements with regard to the Company's business, business practices, risk management or trading activity. The Company denies that it engaged in any improper trading in the California energy market or in any other market, and it denies that the price of its stock was artificially inflated by reason of the misrepresentations and omissions alleged in the lawsuit. There have been no adverse determinations by any court against Avista Corp. or any of the defendants on the merits of the claims asserted by the plaintiffs in the lawsuit, and the Company denies that shareholders were harmed by the conduct alleged in the lawsuit. Neither the settlement agreement nor any of its terms or provisions, nor the Company's decision to settle the lawsuit, should be construed as an admission or concession of any kind of the merit or truth of any of the allegations of wrongdoing in the lawsuit, or of any fault, liability or wrongdoing whatsoever on the part of Avista Corp. The Company believes that throughout the class period alleged in the lawsuit it fully and adequately disclosed all material facts regarding the Company and made no misrepresentations of material facts regarding Avista Corp. The Company nonetheless considers it desirable to settle the lawsuit in order to avoid the cost and risks of further litigation and trial, and to dispose of burdensome and protracted litigation.

In January 2008, the Court granted final approval of the settlement agreement, and entered an order certifying the class and dismissing the claims in the lawsuit with prejudice.

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. In November 2007, the CalISO filed an updated status report at the FERC stating that it continues finalizing the financial adjustment phase, in which the CalISO is making adjustments to its refund rerun settlement data to account for fuel cost allowance offsets, cost-based offsets, and interest calculations. The CalISO states that it has finished processing activities associated with the emissions cost and fuel cost offsets.

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, 2007, 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.

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, if any, of the Company's liability. 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 assert claims for refunds against 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 found the requirement that all sales at market-based rates be contained in quarterly reports filed with the FERC to be integral to a market-based rate tariff. 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. The Court's decision leaves to the FERC the determination as to whether refunds are appropriate. In October 2004, Avista Energy joined with others in seeking rehearing of the Court's decision to remand the case back to the FERC for further proceedings. The Court denied the request without explanation on July 31, 2006. A petition for a writ of certiorari with the United States Supreme Court was denied on June 18, 2007. The proceeding is now on remand before the FERC. 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.

Wah Chang Complaint

In May 2004, Wah Chang, a division of TDY Industries, Inc. (a subsidiary of Allegheny Technologies, Inc.), filed a complaint in the United States District Court for the District of Oregon against numerous companies, including Avista Corp., Avista Energy and Avista Power. This complaint was similar to the Port of Seattle and City of Tacoma complaints (which were dismissed by the United States District Court and the Ninth Circuit as disclosed in the Company's prior Securities and Exchange Commission filings) and was seeking compensatory and treble damages for alleged violations of the Sherman Act, the Racketeer Influenced and Corrupt Organization Act, as well as violations of Oregon state law. According to the complaint, from September 1997 to September 2002, the plaintiff purchased electricity from PacifiCorp pursuant to a contract that was indexed to the spot wholesale market price of electricity. The plaintiff alleged that the defendants, acting in concert among themselves and/or with Enron Corporation and certain affiliates thereof (collectively, Enron) and others, engaged in a scheme to defraud electricity customers by transmitting false market information in interstate commerce in order to artificially increase the price of electricity provided by them, to receive payment for services not provided by them and to otherwise manipulate the market price of electricity, and by executing wash trades and other forms of market manipulation techniques and sham transactions. The plaintiff also alleged that the defendants, acting in concert among themselves and/or with Enron and others, engaged in numerous practices involving the generation, purchase, sale, exchange, scheduling and/or transmission of electricity with the purpose and effect of causing a shortage (or the appearance of a shortage) in the generation of electricity and congestion (or the appearance of congestion) in the transmission of electricity, with the ultimate purpose and effect of artificially and illegally fixing and raising the price of electricity in California and throughout the Pacific Northwest. As a result of the defendants' alleged conduct, the plaintiff allegedly suffered damages of not less than $30 million through the payment of higher electricity prices. In September 2004, this case was transferred to the United States District Court for the Southern District of California for consolidation with other pending actions. In February 2005, the Court granted the defendants' motion to dismiss the complaint because it determined that it was without jurisdiction to hear the plaintiff's complaint, based on, among other things, the exclusive jurisdiction of the FERC and the filed-rate doctrine. In March 2005, Wah Chang filed an appeal with the Ninth Circuit. On November 20, 2007, the Ninth Circuit dismissed Wah Chang's appeal and affirmed the district court's action. On December 3, 2007, Wah Chang filed a petition for rehearing with the Ninth Circuit. On January 15, 2008, the Ninth Circuit denied Wah Chang's petition for rehearing. Based on the Ninth Circuit's dismissal of this complaint and denial of the petition for rehearing, the Company believes that this complaint will not have a material adverse effect on the Company's financial condition, results of operations or cash flows.

State of Montana Proceedings

In June 2003, the Attorney General of the State of Montana (Montana AG) filed a complaint in the Montana District Court on behalf of the people of Montana and the Flathead Electric Cooperative, Inc. against numerous companies, including Avista Corp. The complaint alleges that the companies illegally manipulated western electric and natural gas markets in 2000 and 2001. This case was subsequently moved to the United States District Court for the District of Montana; however, it has since been remanded back to the Montana District Court.

The Montana AG also 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 has 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.

Because the resolution of these proceedings 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 that these proceedings will have a material adverse effect on its financial condition, results of operations or cash flows.

Montana Public School Trust Fund Lawsuit

In October 2003, a lawsuit was originally filed by two residents of the state of Montana in the United States District Court for the District of Montana against private owners of hydroelectric dams in Montana, including Avista Corp. The lawsuit alleged that the hydroelectric facilities are located on state-owned riverbeds and the owners of the dams have never paid compensation to the state's public school trust fund. The lawsuit requested lease payments prospectively and also requested damages for trespassing and unjust enrichment for periods of time dating back to the construction of the respective dams. In May 2004, the Montana AG filed a complaint on behalf of the state in the District Court to join in this lawsuit to allegedly protect and preserve state lands/school trust lands from use without compensation. Through a series of legal developments, the case was subsequently moved to the Montana State Court and the original plaintiffs were removed from the case.

On August 28, 2007, the Montana State Court ruled on several pre-trial motions for summary judgment, finding that, as a matter of law, the Clark Fork River was navigable and the state of Montana owns the riverbeds, that such lands are school trust fund lands, and therefore, the statutes of limitations had not run out on the state of Montana's claims for prior damages.

On October 19, 2007, the Company reached a settlement with the state of Montana resolving this matter. Pursuant to the settlement, Avista Corp. has agreed to make lease payments in the initial amount of $4 million per year beginning February 1, 2008, for the calendar year 2007, and continuing through calendar year 2016, adjusted each year by the Consumer Price Index. On or before June 30, 2016, Avista Corp. and the state of Montana will determine whether the annual lease payments remain consistent with the principles of law as applied to the facts and negotiate an adjusted lease payment for the remaining term of Avista Corp.'s FERC license for its hydroelectric facilities on the Clark Fork River, which expires in 2046. If Avista Corp. and the state of Montana do not agree on an adjusted lease payment, the parties will engage in advisory arbitration and submit the arbitrator's recommendation to the State Board of Land Commissioners (Land Board) for approval. The settlement contains provisions that could reduce the amount of Avista Corp.'s lease payments as a result of future judicial determinations in related cases or governmental actions. Avista Corp. will not make any lease payments for periods prior to 2007.

Avista Corp. and the state of Montana have received a consent decree from the Montana State Court adopting the terms of the settlement, and the settlement was approved by the Land Board. The Company received approval from the WUTC and the IPUC to defer any lease payments as a regulatory asset. The Company believes that such costs will be recovered in future rates based on historical recovery of similar costs.

Colstrip Generating Project Complaints

In May 2003, various parties (all of which are residents or businesses of Colstrip, Montana) filed a consolidated complaint 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 allege damages to buildings as a result of rising ground water, as well as damages from contaminated waters leaking from the lakes and ponds of Colstrip. The plaintiffs are seeking punitive damages, an order by the court to remove the lakes and ponds and the forfeiture of all profits earned from the generation of Colstrip. The owners of Colstrip have undertaken certain groundwater investigation and remediation measures to address groundwater contamination. These measures include improvements to the lakes and ponds of Colstrip.

In March 2007, a group of ranchers filed a consolidated complaint against the owners of Colstrip in Montana District Court. The plaintiffs allege damages to livestock, land and water from contaminated waters leaking from the waste water pond of Colstrip. The plaintiffs are seeking unspecified punitive damages.

The complaints were consolidated and a trial date is scheduled for June 2, 2008. The Company intends to continue to work with the other owners of Colstrip in defense of this consolidated complaint. Because the resolution of this consolidated 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 consolidated 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 issued orders 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, 2004. WECO's appeal to the MMS for the period through 2001 was substantially denied in March 2005; WECO appealed the orders pertaining to the periods up to 2001 to the Board of Land Appeals of the U.S. Department of the Interior, which appeal was denied on September 12, 2007. WECO also filed an appeal with the MMS pertaining to the period from 2002 to 2004. The entire appeal process could take several years to resolve. The owners of Colstrip Units 3 & 4 are monitoring the appeal process between WECO and MMS. WECO has indicated to the owners of Colstrip Units 3 & 4 that if WECO is unsuccessful in the appeal process, WECO will seek reimbursement of any royalty payments by passing these costs through the Coal Supply Agreement. The owners of Colstrip Units 3 & 4 advised WECO that their position would be that these claims are not allowable costs per the Coal Supply Agreement nor the Transportation Agreement in the event the owners of Colstrip Units 3 & 4 were invoiced for these claims. Presumably, royalty and tax demands for periods of time after the years in dispute and future years will be determined by the outcome of the pending proceedings. Because the resolution of this issue remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. 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 rate making process, of any amounts paid.

Spokane River

The Company entered into a settlement with the state of Washington's Department of Ecology (DOE) and Kaiser Aluminum & Chemical Corporation (Kaiser) relating to the remediation of a contaminated site on the Spokane River. The Company's involvement with this contaminated site relates to its previous ownership of a wastewater treatment plant through Avista Development. Kaiser paid the Company approximately 50 percent of the estimated total costs. Under the direction of the Company, work under the Cleanup Action Plan was substantially completed in 2007.

Northeast Combustion Turbine Site

In August 2005, a diesel fuel spill occurred at the Company's Northeast Combustion Turbine generating facility (Northeast CT) located in Spokane, Washington. The Northeast CT site had fuel storage facilities that were leased to Co-op Supply, Inc., an affiliate of Cenex Cooperative (Co-op). The Company immediately commenced remediation efforts, including the removal of contaminated soil and the related fuel storage facilities. The Company accrued the estimated cleanup costs during 2005, which was not material to the Company's consolidated financial condition or results of operations. Through mediation the Company recovered a substantial portion of the cleanup costs from Co-op and an engineering firm in the fourth quarter of 2006. The Company's estimate of its liability could change in future periods. Based on information currently known to the Company's management, the Company does not believe that such a change would be material to its financial condition, results of operations or cash flows.

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp., as a customer 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. 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. 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 $0.6 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 relative volume of waste oil 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 Coeur d'Alene Tribe of Idaho (Tribe) owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Coeur d'Alene Reservation. This action had been brought by the United States on behalf of the Tribe against the state of Idaho. The Company was not a party to this action. The United States District Court decision was affirmed by the Ninth Circuit. The United States Supreme Court affirmed this decision in June 2001. This ownership decision will result in, among other things, the Company being liable to the Tribe for compensation for the use of reservation lands under Section 10(e) of the Federal Power Act.

The Company's Post Falls Hydroelectric Generating Station (Post Falls), a facility constructed in 1906 with annual generation of 10 aMW, utilizes a dam on the Spokane River downstream of the Lake which 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 facilities on the Spokane River downstream of Post Falls, but these facilities do not affect the water level in the Lake. The Company and the Tribe are engaged in discussions related to past and future compensation (which may include interest) for use of the portions of the bed and banks of the Lake, which are owned by the Tribe. If the parties cannot agree on the amount of compensation, the matter could result in litigation. The Company cannot predict the amount of compensation that it will ultimately pay or the terms of such payment. The Company intends to seek recovery, through the rate making process, of any amounts paid.

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 155.7 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 expiration of the current license, an annual license was issued, in effect extending the current license and its conditions until August 1, 2008. 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 has been underway since that time. The Company filed its new license applications with the FERC in July 2005. The Company requested the FERC to consider a license for Post Falls, which has a present capability of 18 MW, that is separate from the other four hydroelectric plants because Post Falls presents more complex issues that may take longer to resolve than those relating to the rest of the Spokane River Project. If granted, new licenses would have a term of 30 to 50 years. 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.

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 Coeur d'Alene 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. The Company's initial estimate of the potential cost of the conditions proposed for Post Falls total between $400 million and $500 million over a 50-year period. For the rest of the Spokane River Project, which is located in Washington, the Company's initial estimate of the cost of meeting the recommended conditions, should they be included in a final license, totaled between $175 million and $225 million over a 50-year period. These cost estimates were based on the preliminary conditions and recommendations.

The Company requested a trial-type hearing in front of an Administrative Law Judge (ALJ) on facts related to the DOI's mandatory conditions for Post Falls. In January 2007, the ALJ issued his ruling regarding the Company's challenge of the facts. The Company believes that the ALJ's findings supported, in several key areas, its analysis of the facts at hand. The ALJ's factual findings also supported the DOI's analysis in certain areas as well.

The DOI issued final mandatory conditions for Post Falls on May 7, 2007, which reflected the findings of the ALJ. Most significantly, the DOI dropped an earlier proposed fishery condition. However, the DOI increased obligations that the Company could incur in other areas, such as wetlands restoration.

In July 2007, the FERC issued a Final Environmental Impact Statement (FEIS) after review and consideration of comments. This is the last administrative step for the FERC before the issuance of license orders; however, the FERC cannot proceed until several other matters are resolved, including Clean Water Act and Endangered Species Act issues as disclosed below. The Company continues to review the FEIS and related documents. While the Company believes the ultimate cost of relicensing will be less than its earlier projections as disclosed above, the Company has not developed specific new cost estimates at this point.

The relicensing process also triggers review under the Endangered Species Act. In the FEIS, the FERC analyzed potential project impacts on listed and threatened endangered species, and has determined that the proposed action and continued operation of Post Falls and the rest of the Spokane River Project is not likely to adversely affect any threatened or endangered species. The Company prepared a draft Biological Assessment in 2005. The FERC has issued a Biological Assessment and formally requested concurrence from the United States Department of Fish and Wildlife Service (USFWS). The USFWS responded by letter, concurring with regards to bald eagles, and requesting additional information regarding bull trout. The Company filed a supplemental report to address the USFWS information request. The Company has continued informal consultation with the USFWS. If the FERC initiates formal consultation with the USFWS, additional evaluation will be required by the Company.

In addition, the Company must receive Clean Water Act Certifications from the states of Idaho and Washington for the Spokane River Project. Applications for such certification were filed in July 2006 with each state. Both Idaho and Washington communicated to the Company that they were unable to complete the certifications within one year as mandated by the Clean Water Act. Subsequently, the Company withdrew these applications and re-filed for certification in June 2007. The FERC is precluded from issuing a license order until such certifications are issued, or waived, by the states. The Company cannot predict the schedule for these final phases of relicensing.

The total annual operating and capitalized costs associated with the relicensing of the Spokane River Project will become better known and estimable as the process continues. The Company intends to seek recovery, through the rate making process, of all such operating and capitalized costs.

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 completed 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 (TDG) 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 will continue meeting with key stakeholders to review and amend the GSCP which includes developing alternatives to the construction of the tunnels. The Company intends to seek recovery, through the rate making process, of the costs to address the dissolved atmospheric gas levels.

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, carbon dioxide, as well as other greenhouse gas and mercury emissions.

In particular, the EPA finalized mercury emission regulations that will affect coal-fired generation plants, including Colstrip. The new EPA regulations establish an emission trading program to take effect beginning in January 2010, with a second phase to take effect in 2018. In addition, in 2006, the Montana Department of Environmental Quality (DEQ) adopted final rules for the control of mercury emissions from coal-fired plants that are more restrictive than EPA regulations. 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. In February 2008, the United States Court of Appeals for the District of Columbia overturned the EPA's mercury emissions regulations. However, this ruling is not expected to affect the Company's current plans to comply with the more restrictive regulations adopted by the Montana DEQ as described below.

Compliance with these 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. Although the mercury reduction targets as mandated by the Montana DEQ have not been achieved, the owners of Colstrip are encouraged with the preliminary results and believe it should be possible to achieve the required emissions levels with further mercury control system optimization. Preliminary estimates indicate that the Company's share of installation capital costs would be $1.3 million and annual operations and maintenance costs would increase by $2.8 million (beginning in mid-2009). The Company will continue to seek recovery, through the rate making 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 utilities (governmental or customer owned). 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. The payments Avista Corp. received under the agreements with the BPA were passed through to its residential and small-farm customers via a credit to their monthly electric bills.

Several public utilities and other parties filed suit against the BPA in the Ninth Circuit, challenging the validity of the agreements between Avista Corp. and the BPA, as well as BPA's agreements with other private utilities. 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. The BPA concluded that the Ninth Circuit's decisions created substantial doubt about whether its certifying official could allow continuation of payments under the settlement agreements. Consequently, on May 21, 2007, the BPA notified Avista Corp. and other private utilities that it was immediately suspending payments the BPA made to them pursuant to the settlement agreements. In its May 21, 2007 notice, the BPA indicated that the suspension of payments would continue at least until any requests for rehearing were filed and the Ninth Circuit issued final decisions on those requests for rehearing. On July 18, 2007 Avista Corp. and numerous other parties, including the Public Utility Commission of Oregon and the WUTC, filed petitions for review, and review en banc, in the Ninth Circuit, challenging the ruling of the panel that struck down the settlement agreements. The Ninth Circuit subsequently denied these requests. Three private utilities, including Avista Corp., filed a petition for writ of certiorari with the United States Supreme Court.

With approval from the WUTC and the IPUC, Avista Corp. eliminated the credit associated with the settlement agreements with the BPA from its customers' monthly electric bills. Avista Corp. has an over-refunded balance of approximately $4.0 million ($3.3 million in Washington and $0.7 million in Idaho) because of the timing of payments received from the BPA and allocation of those funds to customers based on seasonal demand. When the existing rate credit was established it was projected that the balancing account would reach zero at the end of the contract year (October 2007). Avista Corp. is recovering the over-refund in Idaho through an approved surcharge to customers, and expects to ultimately recover the over-refund in Washington, either through a charge to customers or future payments from the BPA.

Beginning in June 2007, the region's private and public utilities worked toward an agreement that would identify an appropriate level of benefits for customers served by the private utilities, including the resolution of outstanding legal issues associated with the May 3 Ninth Circuit opinions. The BPA is working on a long-term resolution of residential exchange issues as part of its 2009 rate case. In addition to resolving residential exchange issues for the long-term, the BPA has also proposed an interim payout of $336 million to private utilities for its fiscal year 2008, to be paid out during the period April 1, 2008 to September 30, 2008. If interim contracts can be successfully executed, the portion of this payout that would benefit Avista Corp.'s customers would have no impact on Avista Corp.'s net income.

Since the residential exchange settlement payments were passed through to Avista Corp.'s customers as adjustments to electric bills, the suspension of payments from the BPA is not expected to have any effect on Avista Corp.'s net income. There is currently not enough information to allow Avista Corp. to assess the probability or amount of any potential liability that may be incurred related to any issues regarding payments made to Avista Corp. pursuant to the settlement agreements. Since 2001, Avista Corp. passed through to its customers approximately $70 million pursuant to the settlement agreements.

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, 2007, 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 2009. Three local agreements in Oregon, which cover approximately 50 employees, expire in April 2010.

NOTE 26: POTENTIAL HOLDING COMPANY FORMATION

At the 2006 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. has 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. If the statutory share exchange and the implementation of the holding company structure are approved by regulators on terms acceptable to the Company, it may be completed sometime in 2008.

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 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 45 percent as of December 31, 2007. 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. The stipulation requires Avista Corp. to increase its actual utility common equity component to 40 percent by June 30, 2008. In addition, 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 27. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2012. Total payments under these contracts were $15.4 million in 2007, $12.5 million in 2006 and $12.8 million in 2005. 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 $14.7 million in 2008, $15.1 million in 2009, $15.4 million in 2010, $14.5 million in 2011 and $14.5 million in 2012. 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 28. DISPOSITION OF SOUTH LAKE TAHOE PROPERTIES

In April 2005, Avista Corp. completed the sale of its South Lake Tahoe, California natural gas properties to Southwest Gas Corporation as part of Avista Utilities' strategy to focus on its business in the northwestern United States. This was the Company's only regulated utility operation in California. The cash proceeds received during 2005 were approximately $16.6 million. The total pre-tax gain for 2005 was $4.1 million related to the Company's disposition of its South Lake Tahoe natural gas properties.

NOTE 29. 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. The Energy Marketing and Resource Management business segment primarily consisted of electricity and natural gas marketing, trading and resource management, including optimization of energy assets owned by other entities and derivative commodity instruments such as futures, options, swaps and other contractual arrangements. On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations. This transaction effectively ends the majority of the operations of the Energy Marketing and Resource Management business segment. This segment still owns natural gas storage facilities and has operating revenues and resource costs related to the power purchase agreement for the Lancaster Plant. 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. 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.

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

	Avista Utilities	Energy Marketing And Resource Management	Advantage IQ	Other	Total Non-Utility	Intersegment Eliminations (1)	Total
For the year ended December 31, 2007:							
Operating revenues	$ 1,288,363	$ 61,541	$ 47,255	$ 20,598	$ 129,394	$ –	$ 1,417,757
Resource costs	780,998	68,676	–	–	68,676	–	849,674
Gross margin	507,365	(7,135)	–	–	(7,135)	–	500,230
Other operating expenses	198,778	14,683	33,841	19,259	67,783	–	266,561
Depreciation and amortization	86,091	548	2,402	1,609	4,559	–	90,650
Income (loss) from operations	150,053	(22,366)	11,012	(270)	(11,624)	–	138,429
Interest expense (2)	86,389	173	194	638	1,005	(954)	86,440
Income taxes	26,663	(5,880)	3,942	(391)	(2,329)	–	24,334
Net income (loss)	43,822	(11,877)	6,651	(121)	(5,347)	–	38,475
Capital expenditures	205,811	318	2,323	639	3,280	–	209,091
For the year ended December 31, 2006:							
Operating revenues	$ 1,267,938	$ 177,551	$ 39,636	$ 21,186	$ 238,373	$ –	$ 1,506,311
Resource costs	751,646	144,137	–	–	144,137	–	895,783
Gross margin	516,292	33,414	–	–	33,414	–	549,706
Other operating expenses	187,457	19,198	27,069	20,279	66,546	–	254,003
Depreciation and amortization	81,904	977	2,088	2,114	5,179	–	87,083
Income (loss) from operations	177,049	13,239	10,479	(1,207)	22,511	–	199,560
Interest expense (2)	95,521	199	609	1,769	2,577	(1,931)	96,167
Income taxes	33,127	6,595	3,616	(1,352)	8,859	–	41,986
Net income (loss)	57,794	11,567	6,255	(2,675)	15,147	–	72,941
Capital expenditures	161,266	1,042	2,627	150	3,819	–	165,085
For the year ended December 31, 2005:							
Operating revenues	$ 1,161,317	$ 167,439	$ 31,748	$ 18,532	$ 217,719	$ (19,429)	$ 1,359,607
Resource costs	669,596	165,423	–	–	165,423	(19,429)	815,590
Gross margin	491,721	2,016	–	–	2,016	–	493,737
Other operating expenses	181,755	18,795	22,738	18,120	59,653	–	241,408
Depreciation and amortization	80,914	1,488	2,037	2,472	5,997	–	86,911
Income (loss) from operations	165,101	(18,267)	6,973	(2,060)	(13,354)	–	151,747
Interest expense (2)	91,847	395	912	1,694	3,001	(2,134)	92,714
Income taxes	29,870	(4,981)	2,147	(1,272)	(4,106)	–	25,764
Net income (loss)	52,299	(8,621)	3,922	(2,612)	(7,311)	–	44,988
Capital expenditures	215,341	1,573	1,106	1,365	4,044	–	219,385
Total Assets:							
As of December 31, 2007	$ 3,009,499	$ 30,690	$ 108,929	$ 40,679	$ 180,298	$ –	$ 3,189,797
As of December 31, 2006	2,895,883	1,017,203	100,431	42,991	1,160,625	$ –	4,056,508

(1) Intersegment eliminations reported as operating revenues and resource costs represent the transactions between Avista Utilities and Avista Energy for energy commodities and services, primarily natural gas purchased by Avista Utilities under the Agency Agreement. Intersegment eliminations reported as interest expense represent intercompany interest.

(2) Including interest expense to affiliated trusts.

NOTE 30. 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. On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations. See Note 3 for further information.

A summary of quarterly operations (in thousands, except per share amounts) for 2007 and 2006 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
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	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
2006				
Operating revenues	$ 499,202	$ 287,394	$ 293,001	$ 426,714
Operating expenses	428,264	244,816	258,910	374,761
Income from operations	70,938	42,578	34,091	51,953
Net income	$ 31,572	$ 13,459	$ 10,073	$ 17,837
Outstanding common stock:				
Weighted average	48,795	48,958	49,098	49,788
End of period	48,886	49,044	49,143	52,514
Total earnings per common share, diluted	$ 0.64	$ 0.27	$ 0.20	$ 0.35
Dividends paid per common share	$ 0.14	$ 0.14	$ 0.145	$ 0.145
Trading price range per common share:				
High	$ 20.67	$ 23.15	$ 25.29	$ 27.52
Low	$ 17.61	$ 19.82	$ 22.38	$ 23.47

NOTE 31. RESTATEMENT OF FINANCIAL STATEMENTS

During preparation of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, the Company determined that SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" was inadvertently not followed in connection with a plan under which benefits are provided to the beneficiaries of former and current executive officers of the Company in case of death. The Company had not previously recognized the actuarial liability or costs relating to this plan in its financial statements since the plan's inception in 1989.

The Company determined that this accounting error was not material to its previously issued financial statements. As such, in accordance with the provisions of Securities and Exchange Commission Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," the Company reflected the correction of this error in subsequent financial statements including the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 and in all subsequent filings with the Securities and Exchange Commission.

Accordingly, the Company's financial statements for 2006 and 2005 were restated. Additionally, the footnotes impacted by these adjustments were restated as well.

The following table summarizes the effects of the restatement (in thousands, except per share amounts):

		2006		2005		2004
	As Previously Reported	As Restated	As Previously Reported	As Restated	As Previously Reported	As Restated
Consolidated Statements of Income:						
Utility operating expenses:						
Other operating expenses	$ 187,161	$ 187,457	$ 181,478	$ 181,755		
Total operating expenses	1,306,455	1,306,751	1,211,676	1,211,953		
Income from operations	199,856	199,560	152,024	151,747		
Income before taxes	115,223	114,927	71,029	70,752		
Income taxes	42,090	41,986	25,861	25,764		
Net income	73,133	72,941	45,168	44,988		
Total earnings per common share, basic	$ 1.49	$ 1.48	$ 0.93	$ 0.93		
Total earnings per common share, diluted	$ 1.47	$ 1.46	$ 0.92	$ 0.92		
Consolidated Statements of Comprehensive Income:						
Net income	$ 73,133	$ 72,941	$ 45,168	$ 44,988		
Comprehensive income	82,295	82,103	42,402	42,222		
Consolidated Balance Sheets:						
Pensions and other postretirement benefits	$ 100,033	$ 103,604				
Deferred income taxes	461,006	459,756				
Total other non-current liabilities and deferred credits	1,131,196	1,133,517				
Total liabilities	3,139,662	3,141,983				
Accumulated other comprehensive loss	(17,966)	(17,816)				
Retained earnings	219,192	216,721				
Total stockholders' equity	916,846	914,525				
Consolidated Statements of Cash Flows:						
Operating Activities:						
Net income	$ 73,133	$ 72,941	$ 45,168	$ 44,988		
Benefit for deferred income taxes	(19,108)	(19,212)	8,865	8,768		
Equity-related AFUDC	–	(2,429)	–	(1,389)		
Other	(18,743)	(16,018)	(5,678)	(4,012)		
Consolidated Statements of Stockholders' Equity:						
Net income	$ 73,133	$ 72,941	$ 45,168	$ 44,988		
Cumulative effect of accounting change	(3,829)	(3,679)				
Accumulated other comprehensive loss	(17,966)	(17,816)				
Retained earnings	219,192	216,721	173,829	171,550	155,854	153,755
Total stockholders' equity	916,846	914,525	771,128	768,849	753,205	751,106

MANAGEMENT'S REPORTS TO AVISTA CORPORATION STOCKHOLDERS

Management's Statement of Responsibility

Management of Avista Corporation is responsible for the accuracy and completeness of the information in this annual report. The financial and operating information presented is derived from company records and other sources. This annual report includes amounts that are based on judgment and estimates where necessary. Disclosure controls and procedures in combination with the Company's internal control over financial reporting provide reasonable assurance that the annual report fairly and reasonably presents the Company's financial position and operating results.

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, 2007 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, 2007.

Scott L. Morris
Chairman, President and
Chief Executive Officer

Malyn K. Malquist
Executive Vice President and
Chief Financial Officer

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, 2007, 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, 2007, 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, 2007 of the Company and our report dated February 26, 2008 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's adoption of a new accounting standard.

Deloitte & Touche LLP

Seattle, Washington
February 26, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the "Company") as of December 31, 2007 and 2006, 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, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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 ("SFAS") No. 123(R), *Share-Based Payment* and adopted 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).*

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, 2007, 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 26, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Seattle, Washington
February 26, 2008

SELECTED FINANCIAL DATA

Avista Corporation

As of and for the years ended December 31

Dollars in thousands, except per share data and ratios

	2007	2006	2005	2004	2003	1997
Financial Results						
Operating revenues	$ 1,417,757	$ 1,506,311	$ 1,359,607	$ 1,151,580	$ 1,123,385	$ 1,301,934
Operating expenses	1,279,328	1,306,751	1,211,953	1,011,110	951,682	1,112,497
Gain on sale of utility properties	–	–	4,093	–	–	–
Income from operations	138,429	199,560	151,747	140,470	171,703	189,437
Interest expense	86,440	96,167	92,714	93,047	92,985	66,275
Income taxes	24,334	41,986	25,764	21,592	35,340	61,059
Income from continuing operations	38,475	72,941	44,988	35,614	50,643	114,767
Loss from discontinued operations	–	–	–	–	(4,949)	30
Net income before cumulative effect of accounting change	38,475	72,941	44,988	35,614	45,694	114,797
Cumulative effect of accounting change	–	–	–	(460)	(1,190)	–
Net income	38,475	72,941	44,988	35,154	44,504	114,797
Preferred stock dividend requirements [1]	–	–	–	–	(1,125)	(5,392)
Income available for common stock	$ 38,475	$ 72,941	$ 44,988	$ 35,154	$ 43,379	$ 109,405
Earnings per common share, diluted:						
Earnings from continuing operations	$ 0.72	$ 1.46	$ 0.92	$ 0.73	$ 1.02	$ 1.96
Loss from discontinued operations	–	–	–	–	(0.10)	–
Earnings before cumulative effect of accounting change	0.72	1.46	0.92	0.73	0.92	1.96
Cumulative effect of accounting change	–	–	–	(0.01)	(0.03)	–
Total earnings per common share, diluted	$ 0.72	$ 1.46	$ 0.92	$ 0.72	$ 0.89	$ 1.96
Total earnings per common share, basic	$ 0.73	$ 1.48	$ 0.93	$ 0.73	$ 0.90	$ 1.96
Common Stock Statistics						
Dividends paid per common share	$ 0.595	$ 0.570	$ 0.545	$ 0.515	$ 0.49	$ 1.24
Book value per common share	$ 17.27	$ 17.41	$ 15.82	$ 15.50	$ 15.54	$ 13.38
Shares of common stock:						
Outstanding at year-end	52,909	52,514	48,593	48,472	48,344	55,960
Average – basic	52,796	49,162	48,523	48,400	48,232	55,960
Average – diluted	52,263	49,897	48,979	48,886	48,630	55,960
Return on average common equity:						
Total company	4.2%	8.7%	5.9%	4.7%	5.9%	15.0%
Utility only	5.8%	9.6%	10.2%	6.6%	7.4%	17.2%
Non-utility only	-3.4%	6.2%	-3.0%	1.0%	3.2%	8.1%
Common stock price:						
High	$ 25.81	$ 27.52	$ 20.20	$ 19.17	$ 18.70	$ 24.81
Low	$ 18.19	$ 17.61	$ 16.31	$ 15.51	$ 9.80	$ 17.38
Year-end close	$ 21.54	$ 25.31	$ 17.71	$ 17.67	$ 18.12	$ 24.31

SELECTED FINANCIAL DATA

Avista Corporation

As of and for the years ended December 31

Dollars in thousands, except per share data and ratios

	2007	2006	2005	2004	2003	1997
Debt and Preferred Stock Statistics						
Pretax interest coverage:						
Including AFUDC/AFUCE	1.75(x)	2.11(x)	1.84(x)	1.60(x)	1.78(x)	3.84(x)
Excluding AFUDC/AFUCE	1.65(x)	2.06(x)	1.80(x)	1.56(x)	1.76(x)	3.79(x)
Embedded cost of long-term debt	7.84%	7.79%	8.09%	8.27%	8.44%	7.61%
Embedded cost of preferred stock	– %	7.39%	7.39%	7.39%	7.35%	8.49%
Credit Ratings (Standard & Poor's/Moody's)						
Senior secured debt	BBB+/Baa2	BBB-/Baa3	BBB-/Baa3	BBB-/Baa3	BBB-/Baa3	A/A3
Senior unsecured debt	BBB-/Baa3	BB+/Ba1	BB+/Ba1	BB+/Ba1	BB+/Ba1	A-/Baa1
Preferred stock	BB/Ba2	BB-/Ba3	BB-/Ba3	BB-/Ba3	BB-/Ba3	A-/Baa1
Financial Condition						
Total assets	$ 3,189,797	$ 4,056,508	$ 4,948,494	$ 3,711,621	$ 3,640,075	$ 2,411,785
Total net utility property	2,351,342	2,215,037	2,126,417	1,956,063	1,914,001	1,433,123
Utility property capital expenditures						
(excluding equity AFUDC)	205,811	161,266	215,341	116,739	102,271	87,175
Long-term debt (including current portion)	948,833	976,459	1,029,514	986,988	954,723	762,185
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	31,500	45,000
Stockholders' equity	$ 913,966	$ 914,525	$ 768,849	$ 751,106	$ 751,252	$ 748,812

(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.*

SELECTED FINANCIAL DATA

Avista Corporation

As of and for the years ended December 31

	2007	2006	2005	2004	2003	1997
Avista Utilities						
Electric Operations						
Electric operating revenues (millions of dollars):						
Residential	$ 251.4	$ 234.7	$ 211.9	$ 209.5	$ 204.8	$ 160.4
Commercial	224.2	221.2	203.5	201.8	201.3	144.9
Industrial	95.2	92.9	91.6	90.3	78.3	58.4
Public street and highway lighting	5.5	5.3	4.9	4.8	4.8	3.4
Total retail revenues	576.3	554.1	511.9	506.4	489.2	367.1
Wholesale revenues	105.7	126.2	151.4	62.4	73.4	329.9
Revenues from sales of fuel	12.9	48.2	41.8	64.0	71.5	–
Other revenues	16.2	18.9	18.0	19.3	16.8	28.9
Total electric operating revenues	$ 711.1	$ 747.4	$ 723.1	$ 652.1	$ 650.9	$ 725.9
Electric energy sales (millions of kWhs):						
Residential	3,670	3,578	3,420	3,343	3,298	3,271
Commercial	3,132	3,110	2,994	2,919	2,919	2,716
Industrial	2,084	2,062	2,091	2,076	1,785	1,759
Public street and highway lighting	26	25	25	25	25	24
Total retail energy sales	8,912	8,775	8,530	8,363	8,027	7,770
Wholesale energy sales	1,594	2,117	2,508	1,472	2,075	16,410
Total electric energy sales	10,506	10,892	11,038	9,835	10,102	24,180
Retail electric customers (average per year):						
Residential	306,737	300,940	294,036	288,422	283,497	261,873
Commercial	38,488	37,912	37,282	36,728	36,279	33,681
Industrial	1,378	1,388	1,408	1,416	1,414	1,145
Public street and highway lighting	426	425	421	418	422	371
Total retail electric customers	347,029	340,665	333,147	326,984	321,612	297,070
Retail electric customers (at year-end):						
Residential	310,701	305,293	298,961	292,150	287,141	265,884
Commercial	39,001	38,362	37,587	37,040	36,551	33,957
Industrial	1,383	1,378	1,393	1,416	1,426	1,003
Public street and highway lighting	427	417	428	408	436	382
Total retail electric customers	351,512	345,450	338,369	331,014	325,554	301,226
Revenue per residential kWh (cents)	6.85	6.56	6.20	6.27	6.21	4.90
Use per residential customer (kWh)	11,965	11,888	11,630	11,591	11,633	12,489
Revenue per commercial kWh (cents)	7.16	7.11	6.80	6.91	6.90	5.34
Use per commercial customer (kWh)	81,377	82,028	80,314	79,465	80,472	80,649
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	3,689	4,128	3,611	3,789	3,540	4,863
Thermal generation (from Company facilities)	3,640	3,434	3,666	2,408	2,398	2,627
Purchased power – long-term hydro contracts	861	787	864	794	775	1,212
Purchased power – wholesale	2,959	3,101	3,519	3,422	3,909	16,038
Power exchanges	(18)	35	10	38	36	178
Total power resources	11,131	1,485	11,670	10,451	10,658	24,918
Energy losses and company use	(625)	(593)	(632)	(616)	(556)	(738)
Total electric energy resources	10,506	10,892	11,038	9,835	10,102	24,180

Avista Corporation

As of and for the years ended December 31

	2007	2006	2005	2004	2003	1997
Electric Operations (continued)						
Total resources available at peak (MW):						
Company owned:						
Hydro	617	980	980	965	955	972
Thermal	830	837	836	532	695	664
Purchased power:						
Long-term hydro contracts	171	143	70	167	174	186
Other	684	658	670	888	733	2,862
Total resources available at peak (winter)	2,302	2,618	2,556	2,552	2,557	4,684
Net system peak demand (winter)	1,685	1,656	1,660	1,766	1,509	1,551
Wholesale obligations	367	431	282	454	417	2,675
Total requirements (winter)	2,052	2,087	1,942	2,220	1,926	4,226
Reserve margin	11%	18%	24%	13%	25%	10%
Annual load factor	61%	59%	56%	62%	65%	63%
Average cost of production (cents per kWh)	3.60	3.33	3.08	2.78	2.76	2.17
Natural Gas Operations						
Natural gas operating revenues (millions of dollars):						
Residential	$ 264.5	$ 257.8	$ 229.7	$ 194.5	$ 166.9	$ 81.9
Commercial	148.4	146.6	126.6	104.7	90.5	42.7
Industrial and interruptible	11.3	11.7	11.9	9.4	7.5	4.1
Total retail revenues	424.2	416.1	368.2	308.6	264.9	128.7
Wholesale revenues	142.2	93.2	58.1	0.2	0.3	19.5
Transportation revenues	6.6	6.5	7.6	8.1	8.5	12.7
Other revenues	4.2	4.8	4.3	3.6	3.6	4.9
Total natural gas operating revenues	$ 577.2	$ 520.6	$ 438.2	$ 320.5	$ 277.3	$ 165.8
Natural gas therms delivered (millions of therms):						
Residential	195.7	192.8	199.4	201.7	198.5	182.1
Commercial	121.6	121.0	123.0	122.8	122.1	118.5
Industrial and interruptible	10.8	11.0	13.5	13.3	12.7	15.7
Total retail	328.1	324.8	335.9	337.8	333.3	316.3
Wholesale	223.1	154.9	72.9	0.3	0.7	105.3
Transportation and other	149.2	150.2	153.5	157.5	156.5	247.2
Total natural gas therms delivered	700.4	629.9	562.3	495.6	490.5	668.8
Retail natural gas customers (average per year):						
Residential	273,415	267,345	265,294	268,571	261,063	214,927
Commercial	32,327	31,746	31,652	31,886	31,312	27,171
Industrial and interruptible	302	295	307	311	310	331
Total retail natural gas customers	306,044	299,386	297,253	300,768	292,685	242,429
Retail natural gas customers (at year-end):						
Residential	277,397	272,109	265,502	272,871	266,252	223,039
Commercial	32,840	32,173	31,476	31,675	31,732	27,699
Industrial and interruptible	298	304	299	304	312	328
Total retail natural gas customers	310,535	304,586	297,277	304,850	298,296	251,066

SELECTED FINANCIAL DATA

Avista Corporation
As of and for the years ended December 31

	2007	2006	2005	2004	2003	1997
Natural Gas Operations (continued)						
Revenue per residential therm (in dollars)	1.35	1.34	1.15	0.96	0.84	0.45
Use per residential customer (therms)	716	721	752	751	760	847
Revenue per commercial therm (in dollars)	1.22	1.21	1.03	0.85	0.74	0.36
Use per commercial customer (therms)	3,760	3,811	3,885	3,853	3,900	4,361
Heating degree days (at Spokane, Washington):						
Actual	6,539	6,332	6,538	6,314	6,351	6,510
30 year average	6,820	6,820	6,820	6,820	6,820	6,842
Actual as a percent of average	96%	93%	96%	93%	93%	95%
Energy Marketing And Resource Management						
Operating revenues (millions of dollars)	$ 61.5	$ 177.5	$ 167.4	$ 275.6	$ 307.1	$ 247.0
Resource costs (millions of dollars)	68.7	144.1	165.4	236.8	246.9	232.4
Gross margin (millions of dollars)	$ (7.2)	$ 33.4	$ 2.0	$ 38.8	$ 60.2	$ 14.6
Gross Physical Realized Sales Volume						
Electricity (thousands of MWhs)	8,715	25,943	28,377	32,629	41,579	4,540
Natural gas (thousands of dekatherms)	43,447	154,808	182,874	219,719	228,397	67,319
Total assets (millions of dollars)	$ 30.7	$ 1,017.2	$ 2,012.4	$ 1,002.8	$ 1,013.2	$ 212.9
Advantage IQ						
Revenues (millions of dollars)	$ 47.3	$ 39.6	$ 31.7	$ 23.4	$ 19.8	$ –
Total assets (millions of dollars)	$ 108.9	$ 100.4	$ 46.1	$ 47.3	$ 45.6	$ –
Other						
Revenues (millions of dollars)	$ 20.6	$ 21.2	$ 18.5	$ 17.1	$ 13.6	$ 163.6
Total assets (millions of dollars)	$ 40.7	$ 43.0	$ 51.9	$ 53.3	$ 48.3	$ 268.7

CORPORATE INFORMATION

Company Headquarters

Avista Corp.
1411 East Mission Avenue
Spokane, Washington 99202

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

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 10 a.m. PDT on Thursday, May 8, 2008, at Avista Corp. headquarters, 1411 East Mission Avenue in 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 6, 2007, the Chief Executive Officer of Avista Corp. filed a Section 303A.12(a) Annual CEO Certification with the New York Stock Exchange. The CEO Certification attests that the Chief Executive Officer 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 Form10-K for the year 2007 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 2007. Our 2007 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; Sharman Communications; Ross Printing; and Avista Corp. Investor Relations, Finance and Corporate Communications.

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