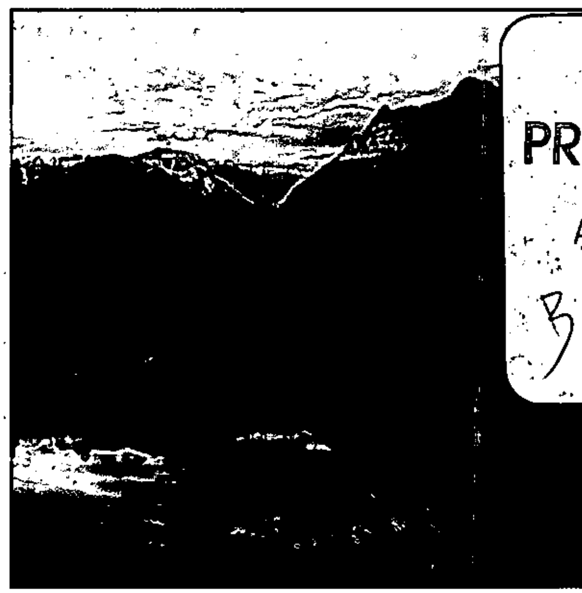
2006 ANNUAL REPORT

Simplify what we do. ***Focus on what we do best.*** Execute well.

our commitments to you



AVISTA Corp.

For more than a century, Avista has delivered reliable performance, value and service. Our core utility business operates in four states, while our subsidiaries extend Avista's utility industry expertise into additional markets.

Avista Utilities reliably delivers energy to more than 345,000 electric and 304,000 natural gas customers in the Pacific Northwest.

Avista Energy leverages our knowledge of energy markets and experience to optimize physical assets in the Western region.

Advantage IQ analyzes utility usage and provides cost management services for national, multi-site companies.

Cover photo:
A wetland that drains into Montana's Bull River, part of our bull trout recovery project.

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FROM THE CHAIRMAN

"As I pass the mantle of leadership on, I have complete confidence that Avista will continue to be a good steward of your investment for generations to come."

We've seen many changes in technology and the way we operate, but the one thing that has never changed is the dedication of our employees and their commitment to reliably serve our customers and bring value to our shareholders.

Gary G. Ely
chairman & chief executive officer
March 9, 2007

At the February 2007 meeting of the board of directors, I announced my retirement as chairman of the board and chief executive officer effective December 31, 2007. That will complete more than 40 years of service in this great company and a career that has been both the most challenging and the most rewarding I could have ever imagined.

Since 1967, the world has changed in ways that were only dreamed of when I started in the engineering department. The company, then known as Washington Water Power, was embarking on a new venture – adding coal-fired steam generation. After 50 years of being 100 percent hydro-based, WWP was doing what the company has always done and will always do – be innovative to assure that the needs of our customers are met.

Today our integrated mix of renewable and traditional resources gives us a balanced portfolio that includes hydro, wind, biomass, natural gas and coal-based fuels for our generation. The concerns regarding greenhouse gases and other man-made impacts on our environment, coupled with the need for increased energy efficiency programs, are important considerations for our future resource planning.

As we entered the 21st century, our company faced the biggest financial challenges in its history. The 2000-2001 energy crisis significantly impacted Avista and now, some six years later, we are emerging a stronger and more vital company.

When I became chairman of the board, president and chief executive officer of the company in 2001, I told Wall Street that we had three commitments that would guide our work: we will simplify what we do; we will focus on what we do best – on what makes a difference to those we serve; and we will execute well. Our employees have kept those commitments.

We refocused on our core business – energy and utility service – and peeled away subsidiary operations that diverted our time and our resources. We began a deliberate and purposeful investment in our infrastructure to enhance the resources we had and to build the ones we needed to meet the growing customer load, while sustaining our commitment to reliability.

We are in the final stages of completing one of the largest transmission projects undertaken by this company in many years. And the 50-year-old hydroelectric facilities at Noxon Rapids and Cabinet Gorge will undergo approximately $35 million of work over the next five years that will enhance their capabilities for generations to come. Our utility capital budget in 2006 totaled $170 million, and projects planned for 2007 call for new investments totaling $180 million.

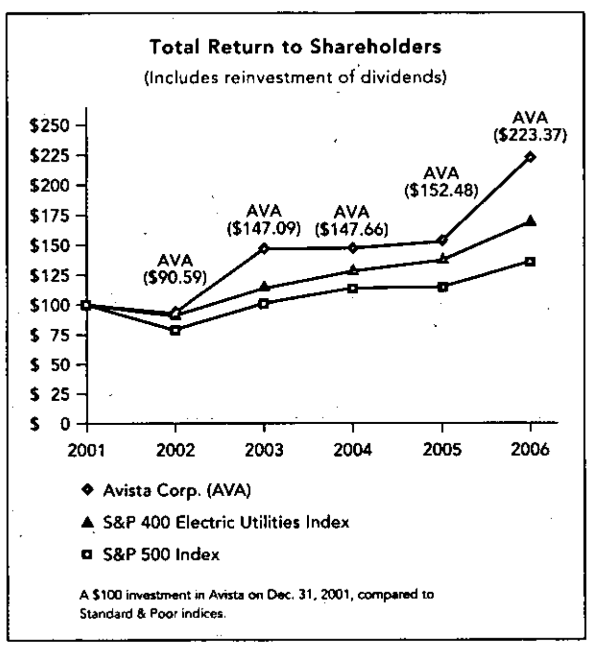
Completion of a five-year transmission extension and upgrade plan in 2007 will enhance reliability and position us to meet growing power demands.

We have worked to improve communication with our state regulators, their staffs and other interested parties to implement rate structures that are fair for our customers and value-based for our shareholders. Through a series of strategic incremental rate requests over the past five years, we have moved to recover the allowed costs of what it takes to run this utility, and we've come very near to earning the rates of return allowed by regulators. As we go forward, we will continue to assess the need for rate relief on a regular basis and develop ways to align our cost recovery, while mitigating the impact on our customers.

The 2000-2001 energy crisis significantly impacted Avista and now, some six years later, we are emerging a stronger and more vital company.

Financially, we have made great progress in recovering our health under the watchful and diligent eye of Malyn Malquist, executive vice president and chief financial officer. Malyn spent a great deal of time scrutinizing processes, assets and resources, asking the tough questions and making sure we are doing everything we can to keep moving forward on our journey to financial health. His efforts have proven successful.

Our total return to shareholders since December 2001 increased nearly 124 percent, significantly outperforming peer utilities in the region and the Standard and Poor's 400 Electric Utilities Index. We've seen interest costs



Since 2001, total return to shareholders increased nearly 124 percent.

decrease. Through the thoughtful management of long-term debt, our debt-to-capitalization ratio decreased by year-end 2006 to 53.7 percent from 60.2 percent a year earlier. In addition, the board of directors authorized five dividend increases in the past three years. We're still working to regain our investment-grade credit rating, and we're hopeful that will come in the year ahead.

Since 2002, earnings per diluted share of common stock have increased 145 percent.

Our subsidiary companies, Advantage IQ and Avista Energy, have certainly faced their own challenges as they have grown and matured in their respective market segments. We are pleased with the progress Advantage IQ has made in customer growth and cost containment. Under the leadership of President Stu Stiles, the company is poised for long-term profitability with strategic investments planned for the next few years. These will set the stage for innovative cost-saving activities that will be ongoing.

Avista Energy performed well in 2006. President and Chief Operating Officer Dennis Vermillion achieved an increase in annual net income primarily due to improved results from natural gas trading activities and the continued execution of profitable transactions in power trading and other asset management and optimization activities. We continue to explore opportunities for this company that will capitalize on its capabilities and strengths under other strategic ownership.

Our leadership team is second to none. Scott Morris, president and chief operating officer of Avista Corp., will succeed me at year-end. His knowledge and talents in the utility field have been instrumental in accomplishing our milestones over the past few years. His vision and leadership are well respected among our employees and our external publics alike, truly carrying forth the legacy this company has established.

The nearly 100-year-old Post Falls Dam is one of five Spokane River hydro facilities up for relicensing.

We've achieved many of the goals I set forth when I became chairman in 2001. But some objectives remain. We are working to change the company structure to a holding company. We've received approvals for the change from you – our shareholders – from the Federal Energy Regulatory Commission, and the Idaho and Washington utility commissions. We also need approvals from Oregon and Montana. I am hopeful we can regain our investment-grade credit rating in the near future and secure a strategic direction for the long-term profitability of Avista Energy. Within the utility, the federal license to operate our hydro facilities on the Spokane River expires in 2007. Our employees are working diligently within the regulatory process and are striving to come to a timely resolution of the remaining issues that is acceptable to everyone.

I am proud of the many milestones we've met in overcoming the challenges our company has encountered. And I am proud of our employees who faced adversity head-on with innovation, integrity, skill and compassion to meet the needs of all of our stakeholders. Beginning in 2008, I look forward to achieving some of my personal goals in service to my church and my community.

It's written that to every thing there is a season. It is now time to pass the mantle of leadership on, and I do this with full confidence in those who will shoulder it – confident that Avista Corp. will continue to be a good steward of your investment for generations to come.

We continuously ***improve how we work,***
operational excellence

offer a smart mix of energy resources,
responsible resources

care for the quality of places we work and live,
environmental stewardship

do the right thing in ***support of our customers,***
customer orientation

and ***earn trust*** as a valued partner.
community partnership

BUSINESS OVERVIEW

The System Operations center is the heart of our utility business. The constant balancing of power requirements with electric and natural gas resources keeps the energy flowing to our customers. This equilibrium and its sustainability are the essence of our business, in all we do.

Malyn K. Malquist
executive vice president & chief financial officer

Scott L. Morris
president & chief operating officer

The Inland Northwest is a region of bountiful natural resources, including powerful water flows that generate the energy upon which this company was founded nearly 120 years ago. Energy and its related businesses have been and will continue to be the focus for our company – reliably bringing electricity and natural gas to our utility customers, optimizing energy use and minimizing energy costs for our customers, and offering valuable returns to those who invest in our company.

avista utilities

In 2006, we identified five strategic priorities, each of which is essential to our continued success, and all of which are the essence of the values we've long held as a company and as individuals.

Operational Excellence: We continually improve how we work. Technology is changing the ways of the world faster than anyone thought possible. We are implementing the best of today's electronic workplace practices to streamline service dispatch, construction work and meter reading. And in 2007, customer transactions will be easier via a leading-edge Web site. These ongoing productivity initiatives will continue to deliver savings and open new career opportunities for our employees.

Responsible Resources: We offer a smart mix of resources to our customers. Avista is a leader in "green" utility operations, with national recognition for some of the lowest emissions among major fossil fuel power generators. Our Kettle Falls Generating Station, for example, is a pioneer in converting waste wood into energy. It uses nearly 500,000 tons of wood waste each year to produce enough electricity to power about 33,000 homes. Our portfolio of renewable resources accounts for more than 60 percent of our total generation. The remainder of our generation comes from natural gas and coal-based resources.

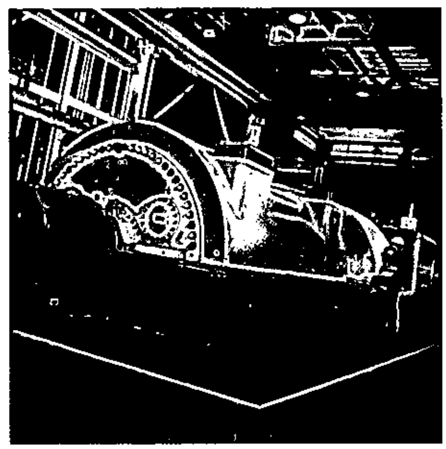
Avista's integrated mix of renewable and traditional resources provides a balanced portfolio that includes hydro, wind, biomass, natural gas, and coal-based fuels.

And as we develop our integrated resource plan for 2007, we will evaluate each resource in the generation mix as well as the potential for adding different sources as the technologies evolve, public policies change and market prices shift.

In the year ahead, we will ramp up our outreach to commercial, industrial and residential customers to help them better manage their energy use – to balance their efficiency and conservation with their business and lifestyle needs.

Our goal remains to have a balanced portfolio of resources to generate sufficient power to meet our customers' needs, with as little dependence on market resources as possible.

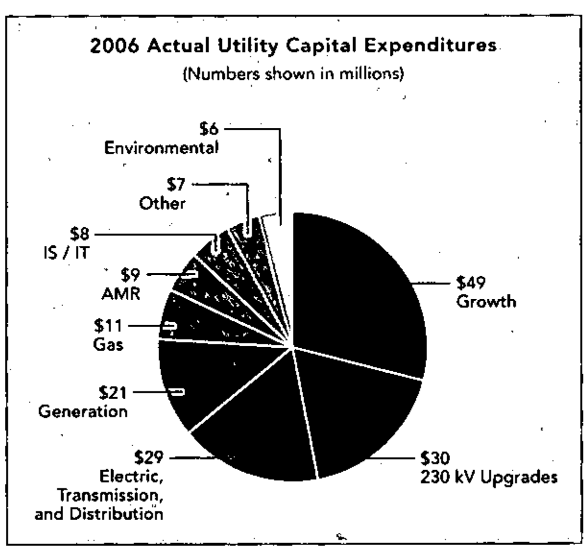
Kettle Falls was the first biomass power plant of its kind in the U.S.



Environmental Stewardship: We care for the quality of the places we work and live. Avista is an award-winning steward of the resources for which we are responsible. We have received eight consecutive annual honors from the National Hydro Association for our care of the rivers from which more than 50 percent of our generation comes. The relicensing process for our five hydro projects on the Spokane River in Idaho and Washington is underway. While it has been challenging, we are hopeful that the collaborative process, involving more than 200 stakeholders, will result in a positive outcome, benefiting the environment, our customers and our communities for generations to come.

We are mindful of the potential environmental impact that disposing of materials and equipment used throughout our system can have. Each year we recycle over 570 tons and reuse a wide variety of materials from our

Investment in capital projects is the result of customer and demand growth. The 2007 utility capital budget is $180 million.



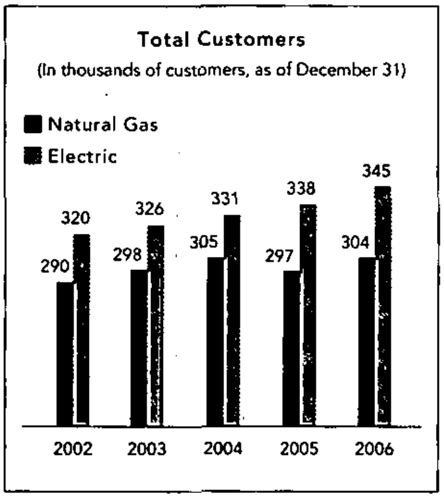
operations, saving more than $500,000 for the company and untold tons of debris from the landfill. This recovery operation has other benefits – it provides work for a group of developmentally disabled community residents – truly a balance of stewardship for the environment with meaningful and rewarding employment.

Overall our goal is to help preserve the great environment that is our home through sustainable operating practices and wise use of our resources.

Customer Orientation: We do the right thing in support of our customers. The need to recover the costs of doing business and keep customer rates affordable and reasonable is an ongoing challenge. Here are some examples of how we strike a balance.

We have put in place rigorous procedures for acquiring natural gas to generate electricity and to help protect our customers from fluctuations in market prices.

Our employees developed and successfully put to use new outage management technology (OMT) that has significantly decreased the time it takes to restore power when outages occur. In fact, using OMT, we estimate we were able to take a full 48 hours off restoration time following a series of severe wind storms late in 2006 that cut power to nearly 113,000 customers.



Avista Utilities is one of the faster growing utilities in the country in terms of customers with 2-3 percent growth expected in 2007.

An enhanced Web site and voice technology system, currently in development, will give customers more flexibility in managing their interactions with us. Customer service is part of our culture at Avista and it shows. We were pleased to achieve customer service satisfaction ratings that exceeded 90 percent in each month of 2006 and that topped out at 94 percent at year end – the seventh consecutive year that overall satisfaction has exceeded the 90 percent mark.

Community Partnership: We earn trust as a valued neighbor. We are an integral and active member of all the communities we serve. We invest our time, talent and treasure in ways that make a difference in the lives of communities, families and individuals. Partnering with others, we give support to those who need it most – the low income and most vulnerable residents of our communities. In the 2005-2006 heating season, over 32,000 households in our service area received energy assistance grants totaling $10.7 million. And together with a local television station, we developed a 30-minute energy conservation program titled "Power to Conserve." Targeted to our senior customers, the program reached more than 120,000 households throughout the region.

The centralization of distribution dispatch marked the end of a four-year effort to link all our distribution feeders to the outage management tool, an application housing geographic information system (GIS) maps of our entire service territory.

Our employees gave 53,000 hours of volunteer service in 2006, positively impacting their communities in ways both large and small. For example, 2006 was the fourth time our Spokane employees joined with local elders and youngsters to grow vegetables in the community garden on our corporate campus, yielding over a ton of fresh produce each season for local assistance organizations. Employees in Coeur d'Alene and Lewiston, Idaho, conducted drives for school supplies and household necessities. We joined with business leaders in Sandpoint, Idaho, to rebuild the strength of the Chamber of Commerce, and we mentored youth through the Junior Achievement program in Medford, Oregon. There are stories like these in every community we serve.

avista energy

Services for clients like Clark County PUD include fuel, power and heat rate optimization at its River Road Generating Plant.

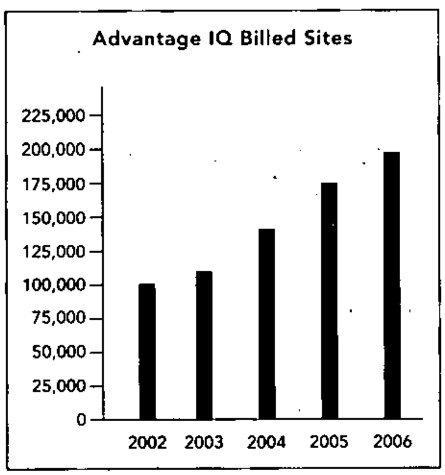
As an energy marketing and trading business, Avista Energy's added value to its customers comes from employees' extensive experience and knowledge of integrated electric and natural gas systems in the west. Its customers are utilities and other end-use businesses. Because Avista Energy operates on an asset-based model, it helps its customers get the most out of their generation facilities through portfolio planning, smart fuel purchasing strategies, long-term sales and trading.

Avista Energy has been a valuable asset to our company, paying approximately $182 million in dividends over the past six years.

Given the significant changes in the energy marketplace over the past few years, the challenge before us now is to evaluate whether we should continue in this business over the long term or if other strategic alternatives may be more appropriate for this business.

advantage IQ

Formerly known as Avista Advantage, this Avista Corp. subsidiary has proven itself a leader in the utility and telecom expense management industry. In 2006, Advantage IQ increased revenue by 25 percent and managed nearly $11 billion in payments to electric, natural gas, water, sewer, waste and telecom utilities for its 370 clients, representing nearly 200,000 billed sites. Those clients are large, multi-location companies, including Starbucks, Citibank, Staples, Wells Fargo, Blockbuster and other national brands. Diversifying Advantage IQ's growth opportunities is a focus for 2007 and beyond, including penetration into current and new markets, as well as enhancing services such as strategic energy management, rate consulting and commodity services offerings. As a 2005 and 2006 Environmental Protection Agency ENERGY STAR® Partner of the Year, Advantage IQ brings additional value to its clients through balancing energy efficiency and cost-saving measures with improved, sustainable and cost-effective operating practices.



The number of billed sites increased about 25,000 or 14 percent during 2006.

As an EPA ENERGY STAR Partner, Advantage IQ brings additional value to its clients.

LEADERSHIP

COMMITTEES

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

Executive Committee
Kristianne Blake
Jack W. Gustavel
R. John Taylor
Gary G. Ely – 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
Jack W. Gustavel
Michael L. Noël
Erik J. Anderson – Chair

Environmental, Safety & Security Committee
Kristianne Blake
Roy L. Eiguren
Lura J. Powell – Chair

BOARD OF DIRECTORS

Erik J. Anderson, 48
President, Westriver Capital,
Kirkland, Washington.
Director since 2000

Kristianne Blake, 53
President, Kristianne Gates Blake, P.S.,
Spokane, Washington.
Director since 2000

Roy Lewis Eiguren, 55
Senior Partner, Givens Pursley LLP,
Boise, Idaho.
Director since 2002

Gary G. Ely, 59
Chairman of the Board & CEO,
Avista Corp.,
Spokane, Washington.
Director since 2001

Jack W. Gustavel, 67
Chairman & CEO,
Idaho Independent Bank,
Coeur d'Alene, Idaho.
Director since 2003

John F. Kelly, 62
President & CEO,
John F. Kelly & Associates,
Paradise Valley, Arizona.
Director since 1997

Scott L. Morris, 49
President & Chief Operating Officer,
Avista Corp.,
Spokane, Washington.
Director since 2007

Michael L. Noël, 65
President, Noël Consulting Company,
Prescott, Arizona.
Director since 2004

Lura J. Powell, Ph.D., 56
President & CEO,
Advanced Imaging Technologies,
Richland, Washington.
Director since 2003

Heidi B. Stanley, 50
Vice Chair & Chief Operating Officer,
Sterling Savings Bank,
Spokane, Washington.
Director since 2006

R. John Taylor, 57
Chairman & CEO, AIA Services
Corporation and CropUSA
Insurance Agency,
Lewiston, Idaho.
Director since 1985

David A. Clack – Retired May 2006
Jessie J. Knight Jr. – Resigned June 2006

CORPORATE AND BUSINESS UNIT OFFICERS

Gary G. Ely, 59
Chairman of the Board &
Chief Executive Officer

Scott L. Morris, 49
President & Chief Operating Officer

Malyn K. Malquist, 54
Executive Vice President &
Chief Financial Officer

Marian M. Durkin, 53
Senior Vice President, General
Counsel & Chief Compliance Officer

Karen S. Feltes, 51
Senior Vice President &
Corporate Secretary

Christy M. Burmeister-Smith, 50
Vice President & Treasurer

James M. Kensok, 48
Vice President & Chief Information
Officer

Don F. Kopczynski, 51
Vice President

David J. Meyer, 53
Vice President & Chief Counsel for
Regulatory & Governmental Affairs

Kelly O. Norwood, 48
Vice President

Ronald R. Peterson, 54
Vice President

Ann M. Wilson, 41
Vice President & Controller

Roger D. Woodworth, 50
Vice President

Stuart A. Stiles, 46
President & Chief Executive Officer
of Advantage IQ

Dennis P. Vermillion, 45
President & Chief Operating Officer
of Avista Energy

FINANCIAL AND OPERATING HIGHLIGHTS

(Dollars in Thousands Except Statistics and Per Share Amounts or as Otherwise Indicated)

	2006	2005	2004
FINANCIAL RESULTS			
Operating revenues	$ 1,506,311	$ 1,359,607	$ 1,151,580
Operating expenses	1,306,455	1,211,676	1,011,110
Gain on sale of utility properties	–	4,093	–
Income from operations	199,856	152,024	140,470
Net income before cumulative effect of accounting change	73,133	45,168	35,614
Cumulative effect of accounting change	–	–	(460)
Net income	$ 73,133	$ 45,168	$ 35,154
Earnings per common share before cumulative effect of accounting change, diluted	$ 1.47	$ 0.92	$ 0.73
Loss per common share from cumulative effect of accounting change, diluted	–	–	(0.01)
Earnings per common share, diluted	$ 1.47	$ 0.92	$ 0.72
Earnings per common share, basic	$ 1.49	$ 0.93	$ 0.73
Dividends paid per common share	0.570	0.545	0.515
Book value per common share	$ 17.46	$ 15.87	$ 15.54
Average common shares outstanding	49,162	48,523	48,400
Actual common shares outstanding	52,514	48,593	48,472
Return on average common equity	8.7%	5.9%	4.7%
Common stock closing price	$ 25.31	$ 17.71	$ 17.67
OPERATING RESULTS			
Avista Utilities:			
Retail electric revenues	$ 554,136	$ 511,864	$ 506,428
Retail kWh sales (in millions)	8,775	8,530	8,363
Retail electric customers at year-end	345,450	338,369	331,014
Wholesale electric revenues	$ 126,208	$ 151,429	$ 62,399
Wholesale kWh sales (in millions)	2,117	2,508	1,472
Total natural gas revenues	$ 520,555	$ 438,205	$ 320,493
Total therms delivered (in thousands)	629,906	562,307	495,584
Retail natural gas customers at year-end	304,586	297,277	304,850
Net income	$ 57,986	$ 52,479	$ 32,467
Energy Marketing and Resource Management:			
Gross margin (operating revenues less resource costs)	$ 33,414	$ 2,016	$ 38,842
Net income (loss)	$ 11,567	$ (8,621)	$ 9,733
kWh sales (in millions)	25,943	28,377	32,629
Natural gas sales (thousands of dekatherms)	154,808	182,874	219,719
Advantage IQ:			
Revenues	$ 39,636	$ 31,748	$ 23,444
Net income	6,255	3,922	577
Other:			
Revenues	$ 21,186	$ 18,532	$ 17,127
Net loss	(2,675)	(2,612)	(7,623)
FINANCIAL CONDITION			
Total assets	$ 4,056,508	$ 4,948,494	$ 3,711,621
Long-term debt	949,854	989,990	901,556
Long-term debt to affiliated trusts	113,403	113,403	113,403
Preferred stock (subject to mandatory redemption)	26,250	28,000	29,750
Common equity	916,846	771,128	753,205

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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 assumptions underlying them (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.

All 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, 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 and unrealized gains and losses;
- volatility and illiquidity in wholesale energy markets, including the availability 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 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 concerning us or affecting directly or indirectly our operations;
- the potential effects of any legislation or administrative rulemaking passed into law, including the possible adoption of national, regional, or state restrictions on greenhouse gas emissions and global warming;
- changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies, including present and potential environmental remediation costs;
- the potential impact of changes to electric transmission ownership, operation and governance, such as the formation of one or more regional transmission organizations or similar entities;
- 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 and monetary policy;
- changes in industrial, commercial and residential growth and demographic patterns in our service territory;
- the loss of significant customers and/or suppliers;
- failure to deliver on the part of any parties from which we purchase and/or sell capacity or energy;
- changes in the creditworthiness of our customers and energy trading 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 premiums paid for 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 quickly obsolete;
- changes in tax rates and/or policies; and

- changes in our strategic business plans and/or our subsidiaries, 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 have a reasonable basis including, without limitation, an examination of historical operating trends, data contained in our records and other data available from third parties. However, there can be no assurance that our expectations, beliefs or projections will be achieved or accomplished. Furthermore, any forward-looking statement speaks only as of the date on which such statement is made. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of such factors, nor can we assess the effect of each such factor on our business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

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

POTENTIAL HOLDING COMPANY FORMATION

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 after mid-2007. See further information at "Note 26 of the Notes to Consolidated Financial Statements."

BUSINESS SEGMENTS

We have four 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 are conducted primarily by Avista Energy, Inc., an indirect subsidiary of Avista Corp.
- **Advantage IQ (formerly Avista Advantage)** – facility information and cost management services for multi-site customers. The activities of this business segment are conducted by Advantage IQ, Inc., an indirect subsidiary of Avista Corp.
- **Other** – includes sheet metal fabrication, venture fund investments and real estate investments. The activities of this business segment are conducted by various indirect subsidiaries of Avista Corp., including Advanced Manufacturing and Development (AM&D), doing business as METALfx.

Avista Energy, Advantage IQ and the various companies in the Other business segment are subsidiaries of Avista Capital, which is a direct, wholly owned subsidiary of Avista Corp. Our total common stockholders' equity was $916.8 million as of December 31, 2006, of which $247.2 million represented our investment in Avista Capital.

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

	2006	2005	2004
Avista Utilities	$ 57,986	$ 52,479	$ 32,467
Energy Marketing and Resource Management	11,567	(8,621)	9,733
Advantage IQ	6,255	3,922	577
Other	(2,675)	(2,612)	(7,163)
Net income before cumulative effect of accounting change	73,133	45,168	35,614
Cumulative effect of accounting change	-	-	(460)
Net income	$ 73,133	$ 45,168	$ 35,154

EXECUTIVE LEVEL SUMMARY

Overall

Our operating results and cash flows are 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
- Advantage IQ.

We intend to continue to focus on improving earnings and operating cash flows, controlling costs and reducing debt while working to restore an investment grade credit rating.

Our net income was $73.1 million for 2006 compared to $45.2 million for 2005. This increase was due to the improved performance for each segment except for the Other segment. The most significant improvement was in the Energy Marketing and Resource Management segment (Avista Energy).

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, a reduction in precipitation (particularly winter snowpack) can negatively impact electric resource costs by decreasing hydroelectric generation capability and increasing the costs for fuel to run thermal generation. This also increases the need for cash to purchase electric resources in the wholesale market. 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 the cost of fuel for electric generation and wholesale electric market prices.

Our hydroelectric generation was 104 percent of normal in 2006. Our hydroelectric generation has been below normal (based on a 70-year average) for five of the past seven years. For 2007, we are forecasting hydroelectric generation to be normal. This 2007 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 the risk of 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 and unrealized gains and losses. Our utility operation 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 above the level currently recovered in retail rates during periods when the utility must purchase energy, power and natural gas deferral balances will increase. This would negatively affect utility operating cash flow and liquidity until such costs, with interest, are recovered from customers.

In December 2005, we received approval from the Washington Utilities and Transportation Commission (WUTC) to increase base electric and natural gas rates effective January 1, 2006. In December 2006, the WUTC dismissed our request to increase electric rates for Washington customers. We are not expecting to receive any significant rate adjustments in 2007. We expect to file a general rate case in Washington during the first half of 2007. Any rate adjustments, if approved by the WUTC, would most likely become effective beginning sometime in 2008.

Our utility net income was $58.0 million for 2006, an increase from $52.5 million for 2005 primarily due to an increase in gross margin (operating revenues less resource costs). The increase in gross margin was partially offset by an increase in other operating expenses, taxes other than income taxes and interest expense. The increase in gross margin was due in part to a decrease in electric resource costs as compared to the amount included in base retail rates. We recognized a benefit of $2.6 million under the Washington Energy Recovery Mechanism (ERM) for 2006 compared to an expense of $9.5 million under the ERM for 2005. In addition, the general rate increase implemented in Washington contributed to the increase in gross margin and net income.

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 $161.3 million for 2006. We are expecting utility capital expenditures to be $180 million for 2007. Significant projects include the continued enhancement of our transmission system and upgrades to our generation facilities.

Our filing to increase electric rates in Washington was dismissed and we expect to absorb expenses under the ERM in 2007 as compared to a benefit in 2006. Based primarily on these factors, utility net income may decrease for 2007 as compared to 2006.

Energy Marketing and Resource Management (Avista Energy)

The activities of Avista Energy, our energy marketing and resource management subsidiary, include:

- 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 Canada, Ltd. (Avista Energy Canada) is a wholly owned subsidiary of Avista Energy that provides natural gas services to end-user industrial and commercial customers in British Columbia, Canada.

Our earnings and cash flows from this business segment are by nature subject to significant variability because they are 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 are 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 are subject to variability caused by the differences between the estimated market value and the required accounting for these assets and contracts. While we have taken measures to enhance profitability and reduce the risk of losses in the future, this business segment will continue to have variable results.

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.

Our Energy Marketing and Resource Management segment had net income of $11.6 million for 2006 compared to a net loss of $8.5 million for 2005. The difference between the estimated market value and the required accounting for certain contracts and physical assets under management reduced net income by $2.2 million from this segment for 2006 and decreased the net loss by $0.4 million for 2005. The net loss for 2005 was primarily due to losses in Avista Energy's natural gas portfolio. The volatility in natural gas and electricity prices can result in significant variability in earnings from this segment.

Given the significant changes in the energy marketplace over the past few years, the challenge before us now is to explore whether we should continue in this business over the long term or if any strategic alternatives may be available that will allow Avista Energy to grow and reach its earnings potential.

Advantage IQ

Our subsidiary, Advantage IQ, had net income of $6.3 million for 2006, an increase from $3.9 million for 2005, primarily due to increased operating revenues. This was a result of customer growth and an increase in interest earnings on funds held for customers.

We are implementing certain strategic investments at Advantage IQ aimed at creating long-term savings that will increase operating and capitalized costs in the short-term through up-front expenditures. This could limit earnings growth from this segment in 2007 while enhancing the long-term profit potential of Advantage IQ.

Other Business Segment

Over time as opportunities arise, we plan to dispose of assets and phase out operations in the Other business segment. However, we may invest incremental funds in these businesses to protect existing investments. The net loss in our Other business segment was $2.7 million for 2006, compared to a net loss of $2.6 million for 2005. We are not expecting a significant change in results from this business segment for 2007 as compared to 2006.

Liquidity and Capital Resources

In April 2006, we amended our committed line of credit agreement that was originally entered into in December 2004. Amendments to the committed line of credit included a reduction in the total amount of the facility to $320.0 million from $350.0 million and an extension of the expiration date to April 2011 from December 2009. We chose to reduce the facility based on our forecasted liquidity needs.

In March 2006, we amended our accounts receivable sales facility to extend the termination date to March 2007. We expect to renew this facility before the March 2007 expiration. Under this facility, we can sell without recourse, on a revolving basis, up to $85.0 million of accounts receivable.

Avista Energy has a $145.0 million committed line of credit that expires in July 2007 and expects to renew this facility.

In December 2006, we issued $150.0 million of long-term debt through underwriters to legally defease debt that was scheduled to mature in January 2007, and we issued 3,162,500 shares of common stock through an underwriter and received net proceeds of $77.7 million.

Also, 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. As of February 26, 2007, we have not issued any shares under the sales agency agreement. We plan to issue these shares over the next 2 years.

These financing transactions are part of the overall plan to reduce debt service costs and improve capitalization ratios as part of the continuing process of improving our corporate financial health. This should assist us in meeting certain equity targets required through regulatory orders and agreements and ultimately restore an investment grade credit rating.

For 2007, 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,
- maturing long-term debt and preferred stock,
- dividends, and
- other contractual commitments.

Succession Planning

We have management succession plans that work toward ensuring that executive officer and key management positions can be appropriately filled as vacancies occur. We also have workforce development plans for key technical and craft areas.

On February 9, 2007, Gary G. Ely, Chairman of the Board and Chief Executive Officer of Avista Corp., announced to the Company's board of directors, that he will retire from the Company and the board effective December 31, 2007. Following Mr. Ely's announcement, the Company's board of directors appointed Scott L. Morris, President and Chief Operating Officer of Avista Corp. to serve as a director on the board. The Company's board of directors also elected Mr. Morris to the positions of Chairman of the Board and Chief Executive Officer of Avista Corp. effective January 1, 2008.

AVISTA UTILITIES – ELECTRIC RESOURCES

As of December 31, 2006, our generation facilities had a total net capability of 1,805 MW, of which 54 percent was hydroelectric and 46 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, 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. As discussed on page 5, our request for rate relief through a production/transmission update was not approved by the WUTC. As such, we expect to file a general rate case in Washington during the first half of 2007.

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 2006	9.11%	10.40%	40%
Idaho electric and natural gas	September 2004	9.25%	10.40%	43%
Oregon natural gas	October 2003	8.88%	10.25%	48%

In December 2005, the WUTC approved our combined electric and natural gas general rate case settlement agreement with certain conditions. The conditions were subsequently accepted by the settling parties (Avista Utilities, the WUTC staff, the Northwest Industrial Gas Users and the Energy Project). The WUTC Order provided for base rate increases of 7.5 percent for electric and 0.6 percent for natural gas, effective January 1, 2006. The electric base rate increase was designed to increase annual revenues by $21.4 million. The majority of the increase in electric revenues is related to increased power supply costs. As such, a significant portion of the increase does not increase gross margin or net income, because it is matched by an increase in the amount of resource costs that we recognize in expense. The natural gas base rate increase was designed to increase annual revenues by $1.0 million. The WUTC Order also provided for further review of the ERM as discussed at "Power Cost Deferrals and Recovery Mechanisms" below.

As part of the general rate case settlement agreement that was modified and approved by the WUTC Order, 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 38.1 percent as of December 31, 2006.

In January 2005, the WUTC issued its final order for a natural gas general rate case filed by us in Washington. The final order authorized, among other things, an increase in natural gas rates of 3.9 percent, which was designed to increase annual revenues by $5.4 million.

In October 2004, the IPUC issued its final order for electric and natural gas general rate cases filed by us in Idaho. The final order authorized, among other things, increases to electric base rates of 16.9 percent and natural gas base rates of 6.4 percent. This was designed to increase annual electric revenues by $24.7 million and annual natural gas revenues by $3.3 million. Due to a decrease implemented concurrently in the power cost adjustment (PCA) surcharge and certain other minor adjustments, the net increase in electric rates for our Idaho customers was 1.9 percent above rates in effect at that time. Based on the final order issued by the IPUC, we had to write off a total of $14.4 million of costs in 2004.

Production/Transmission Update

On December 26, 2006, the WUTC issued an order granting a motion to dismiss our request to increase electric rates for Washington customers. We filed this production/transmission update request with the WUTC in August 2006. On October 27, 2006, the Industrial Customers of Northwest Utilities (ICNU) and the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) filed this motion to dismiss claiming that, among other things, the production/transmission update filing represented improper single-issue ratemaking and violated a prior ERM stipulation, as well as rate case filing requirements. ICNU and Public Counsel contended that the costs at issue should be addressed in a general rate case filing. The WUTC order granting the motion to dismiss concluded that our filing was by definition a general rate case and that the filing failed to comply with applicable rules.

Oregon Senate Bill 408

The Public Utility Commission of Oregon (OPUC) issued final rule that relate 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 final 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 new rules, we will compute 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 will 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 in December 2006. The private letter ruling request seeks guidance on whether OSB 408 and the related OPUC orders violate normalization rules for accounting for income taxes. Certain parties (including Avista Corp.) are seeking legislative changes related to OSB 408. Based on an analysis of operating results for prior years and current rules, we recorded a liability for potential refunds to our customers of $1.3 million in 2006.

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 customer usage due to conservation and price elasticity. However, it will 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. The filing of the first decoupling rate adjustment will be in the fall of 2007.

Accounting Order 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 agreed to file a request with the WUTC for an accounting order supporting our accounting treatment of debt repurchase costs. The filing was made on February 13, 2007. In that filing, we agreed that costs associated with any new repurchases of debt would be accounted for in accordance with FERC General Instruction 17 (FERC 17), and in the event we desire to account for the cost of new debt repurchases differently than 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 to accomplish the repurchase, then these costs can be amortized over the life of the new debt. We have accounted for debt repurchase costs in accordance with regulatory accounting practices under SFAS No. 71. These costs are amortized over the average remaining maturity of outstanding debt and recovered through retail rates as a component of interest expense. In our request for an accounting order, we are not proposing to change the amortization method for debt repurchase costs incurred prior to December 31, 2006.

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

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 deadband amount was $9.0 million since the implementation of the ERM on July 1, 2002, and we expensed the entire deadband each year through 2005 because power supply costs exceeded the amount included in base retail rates by more than $9.0 million.

The WUTC rejected the proposal in our rate case settlement agreement to reduce the ERM deadband from $9.0 million to $3.0 million. However, we were directed to make a filing with the WUTC by January 31, 2006, to allow further review of the ERM. On January 31, 2006, we made a filing with the WUTC proposing that the ERM be continued for an indefinite period of time and that the $9.0 million deadband be eliminated. This filing also satisfied a previous requirement for us to make a filing by the end of 2006 for a review of the ERM.

On June 16, 2006, the WUTC approved a settlement agreement between the Company, the staff of the WUTC, the Industrial Customers of Northwest Utilities and the office of Public Counsel Section of the Washington Attorney General's Office, representing all parties in our ERM proceeding. The settlement agreement provides for the continuation of the ERM with certain agreed-upon modifications and is effective as of January 1, 2006. The settling parties have agreed to review the ERM after five years.

The settlement agreement modified the ERM such that the annual deadband was reduced from $9.0 million to $4.0 million. We will 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 will incur the cost of, or receive the benefit from, the remaining 50 percent. Once 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 will 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 historical (before January 1, 2006) and modified ERM (effective January 1, 2006):

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
Historical ERM:		
+/- $0 - $9 million	0%	100%
+/- excess over $9 million	90%	10%
Modified ERM:		
+/- $0 - $4 million	0%	100%
+/- between $4 million - $10 million	50%	50%
+/- excess over $10 million	90%	10%

Under the ERM, we will continue to make an annual filing on or before April 1st of each year to provide the opportunity for the WUTC and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by WUTC order. In June 2006, the WUTC issued an order, which approved the recovery of the $4.1 million of deferred power costs that we incurred in 2005.

We have a PCA mechanism in Idaho that allows us to modify electric rates periodically with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. The PCA rate surcharge is currently 2.5 percent.

The following table shows activity in deferred power costs for Washington and Idaho during 2005 and 2006 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2004	$ 113,208	$ 9,498	$ 122,706
Activity from January 1 – December 31, 2005:			
Power costs deferred	4,129	3,938	8,067
Interest and other net additions	5,403	278	5,681
Recovery of deferred power costs through retail rates	(26,549)	(5,727)	(32,276)
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

Purchased Gas Adjustments

Effective in October and November of 2005, natural gas rates were increased:

- 23.5 percent in Washington,
- 23.8 percent in Idaho; and
- 22.5 percent in Oregon.

Effective November 1, 2006, natural gas rates:

- increased 1.3 percent in Washington,
- decreased 3.4 percent in Idaho, and
- increased 6.9 percent in Oregon.

These natural gas rate increases and decreases are designed to pass through changes in purchased natural gas costs to our customers with no change in gross margin or net income. The increase in Oregon was approved subject to refund pending further review of our natural gas purchasing and hedging strategies. We have entered into a settlement agreement with the OPUC staff and the Northwest Industrial Gas Users related to this review, which is subject to approval by the OPUC. Total deferred natural gas costs were $18.3 million as of December 31, 2006, a decrease from $43.4 million as of December 31, 2005 primarily due to recovery from customers during 2006.

LEGAL AND REGULATORY PROCEEDINGS IN WESTERN POWER MARKETS

We are involved in a number of legal and regulatory proceedings and complaints with respect to power markets in the western United States. Most of these proceedings and complaints relate to the significant increase in the spot market price of energy in western power markets in 2000 and 2001, which allegedly contributed to or caused unjust and unreasonable prices. These proceedings and complaints include, but are not limited to:

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

As a result of these proceedings and complaints, certain parties have asserted claims for refunds and damages from us (primarily through Avista Energy), which could result in a negative effect on future earnings. However, we believe that we have adequate reserves established for refunds that may be ordered. We have joined other parties in opposing these refund claims and complaints for damages. See further information in "Note 25 of the Notes to Consolidated Financial Statements."

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 Other) that follow this section.

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 Statement of Financial Accounting Standards (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 business segment 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 business segment.

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 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.

2005 compared to 2004

Utility revenues increased $188.7 million due to increases in:

- natural gas revenues of $117.7 million reflecting an increase in natural gas wholesale sales and an increase in retail natural gas sales as a result of rate increases, and
- electric revenues of $71.0 million reflecting an increase in wholesale revenues and a slight increase in retail revenues, partially offset by a decrease in sales of fuel.

Non-utility energy marketing and trading revenues increased $9.6 million primarily due to increased revenues for Avista Energy Canada, partially offset by decreased net trading margin on contracts accounted for under SFAS No. 133.

Other non-utility revenues increased $9.7 million to $50.3 million as a result of increased revenues from:

- Advantage IQ of $8.3 million primarily due to customer growth, and
- the Other business segment of $1.4 million primarily due to increased sales at AM&D.

Utility resource costs increased $150.6 million primarily due to increased:

- purchased natural gas costs of $109.9 million, and
- purchased power costs of $41.4 million.

The increase in purchased natural gas and power costs was primarily due to an increase in prices, as well as an increase in the volume of purchases.

Utility other operating expenses increased $1.1 million primarily due to an increase in incentive compensation expenses including performance share payouts, partially offset by a decrease in certain other operating expenses. These decreases in certain other operating expenses included the sale of our South Lake Tahoe natural gas operations and write-offs related to the Idaho general rate case that we incurred in 2004.

Utility depreciation and amortization expense increased $8.1 million due in part to plant additions and the resulting increase in depreciation expense. Our utility capital expenditures were $215.3 million in 2005. The increase in utility depreciation and amortization expense was also due to a correction for overstated depreciation expense in prior periods that we recorded in 2004.

Non-utility resource costs increased $46.4 million primarily due to increased resource costs for Avista Energy Canada and partially due to an increase in transportation and transmission costs.

Other non-utility operating expenses decreased $7.7 million due to:

- asset impairment charges recorded at Avista Power in 2004,
- decreased compensation expense at Avista Energy in 2005,
- the impairment of goodwill at AM&D in 2004,
- the accrual of environmental liabilities at Avista Development in 2004, and
- the write-off of an investment in a natural gas storage project in 2004 (Other business segment).

These changes were partially offset by increased operating expenses for Advantage IQ in 2005 due to expanding operations.

Interest expense decreased $0.8 million primarily due to a decrease in the effective borrowing rate on our long-term debt as a result of previous debt issuances and repurchases, partially offset by an increase in interest expense on short-term borrowings.

Interest expense to affiliated trusts increased $0.4 million due to increased interest rates on variable rate debt.

Other income-net increased $1.6 million primarily due to an increase in our interest income.

Income taxes increased $4.3 million primarily due to an increase in income before income taxes. Our effective tax rate was 36.4 percent for 2005 compared to 37.7 percent for 2004. The decrease in the effective tax rate was partially due to tax credits for our Kettle Falls Generation Plant that we began receiving the benefit from in 2005.

During 2004, we recorded as a cumulative effect of accounting change a charge of $0.5 million for the implementation of Financial Accounting Standards Board Interpretation No. 46, "Consolidation of Variable Interest Entities," which was revised in December 2003. This required Avista Ventures to consolidate several minor entities and the charge was reflected in the Other business segment.

AVISTA UTILITIES

2006 compared to 2005

Net income for the utility was $58.0 million for 2006 compared to $52.5 million for 2005. Utility income from operations was $177.3 million for 2006 compared to $165.4 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 utility 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.

The increase in use per customer was 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.

2005 compared to 2004

Net income for the utility was $52.5 million for 2005 compared to $32.5 million for 2004. Utility income from operations was $165.4 million for 2005 compared to $134.1 million for 2004. This increase was primarily due to increased gross margin (operating revenues less resource costs) as a result of:

- general rate increases,
- the IPUC related write-offs of $14.4 million ($9.4 million, net of taxes) in 2004, and
- the $4.1 million pre-tax gain related to the sale of our South Lake Tahoe natural gas properties in 2005.

These increases were partially offset by an increase in depreciation expense, taxes other than income taxes and other operating expenses.

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

	Electric		Natural Gas		Total	
	2005	2004	2005	2004	2005	2004
Operating revenues	$ 723,112	$ 652,081	$ 438,205	$ 320,493	$ 1,161,317	$ 972,574
Resource costs	343,945	300,958	325,651	218,044	669,596	519,002
Gross margin	$ 379,167	$ 351,123	$ 112,554	$ 102,449	$ 491,721	$ 453,572

Operating revenues increased $188.7 million and resource costs increased $150.6 million. As such, our gross margin increased of $38.1 million. Our gross margin increased $28.0 million for electric sales and $10.1 million for natural gas sales.

The increase in our electric gross margin was primarily due to:

- the IPUC's disallowance of $12.0 million in deferred power costs in 2004,
- the Idaho electric general rate increase implemented in September 2004, and
- customer growth.

The increase in our natural gas gross margin was primarily due to:

- the Idaho natural gas general rate increase implemented in September 2004,
- the Washington natural gas general rate increase implemented in November 2004, and
- customer growth in the Washington, Idaho and Oregon service territories.

The effects of general rate increases and customer growth were 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	
	2005	2004	2005	2004
Residential	$ 211,934	$ 209,518	3,420	3,343
Commercial	203,480	201,775	2,994	2,919
Industrial	91,552	90,288	2,091	2,076
Public street and highway lighting	4,898	4,847	25	25
Total retail	511,864	506,428	8,530	8,363
Wholesale	151,429	62,399	2,508	1,472
Sales of fuel	41,831	63,990	-	-
Other	17,988	19,264	-	-
Total	$ 723,112	$ 652,081	11,038	9,835

Retail electric revenues increased $5.4 million due to an increase in total MWhs sold (increased revenues $10.0 million), partially offset by a decrease in revenue per MWh (decreased revenues $4.6 million). The increase in total MWhs sold was primarily due to customer growth and increased use per customer from colder weather during the fourth quarter heating season, partially offset by warmer weather during the first quarter heating season and colder weather during the third quarter cooling season. Total heating degree days at Spokane, Washington for 2005 increased as compared to 2004 with both periods warmer than normal. Total cooling degree days at Spokane, Washington for 2005 decreased as compared to 2004 with both periods warmer than normal. In September 2004, we implemented a general electric rate increase in Idaho (with regulatory approval). However, this was almost entirely offset by a decrease in the PCA surcharge, such that the net increase in rates for our Idaho customers was only 1.9 percent. Although the Idaho general rate case increased gross margin, income from operations and net income for 2005 as compared to 2004, it did not have a significant effect on our operating revenues.

Wholesale electric revenues increased $89.0 million due to increased:

- volumes (increased revenues $62.6 million) reflecting added generation capacity, earlier than normal and better than anticipated runoff to our hydroelectric generating assets during 2005 and retail loads that were lower than anticipated, which resulted in excess resources that were sold in the wholesale market, and
- prices (increased revenues $26.4 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 $22.2 million as a greater percentage of our fuel purchases were used in generation.

Other electric revenues decreased $1.3 million primarily due to decreased transmission revenues.

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	
	2005	2004	2005	2004
Residential	$ 229,737	$ 194,470	199,433	201,696
Commercial	126,648	104,754	122,981	122,852
Industrial	11,867	9,423	13,534	13,274
Total retail	368,252	308,647	335,948	337,822
Wholesale	58,074	152	72,903	305
Transportation	7,601	8,134	152,990	154,427
Other	4,278	3,560	466	3,030
Total	$ 438,205	$ 320,493	562,307	495,584

Natural gas revenues increased $117.7 million due to an increase in retail natural gas revenues and wholesale natural gas revenues. The $59.6 million increase in retail natural gas revenues was primarily due to an increase in our retail rates (increased revenues $61.7 million), partially offset by a decrease in volumes (decreased revenues $2.1 million). During October and November of 2005, we increased retail rates for natural gas (with regulatory approval) in response to an increase in natural gas costs. In September and November 2004, we implemented general natural gas rate increases (with regulatory approval) in Idaho and Washington. The decrease in total therms sold was primarily due to the sale of our South Lake Tahoe properties, partially offset by customer growth in our other service territories and a slight increase in use per customer. The increase in our wholesale revenues 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	
	2005	2004	2005	2004
Residential	294,036	288,422	265,294	268,571
Commercial	37,282	36,728	31,652	31,886
Industrial	1,408	1,416	307	311
Public street and highway lighting	421	418	-	-
Total retail customers	333,147	326,984	297,253	300,768

The decrease in our average number of natural gas retail customers was due to the sale of our South Lake Tahoe, California natural gas properties in April 2005. We had 18,750 customers in South Lake Tahoe, California as of December 31, 2004.

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

	2005	2004
Electric resource costs:		
Power purchased	$ 186,703	$ 145,298
Power cost amortizations, net of deferrals	24,209	22,950
Fuel for generation	93,034	38,406
Other fuel costs	36,636	72,602
Other regulatory amortizations, net	(6,532)	(2,529)
Other electric resource costs	9,895	24,231
Total electric resource costs	343,945	300,958
Natural gas resource costs:		
Natural gas purchased	335,796	225,908
Natural gas deferrals, net of amortizations	(13,912)	(12,136)
Other regulatory amortizations, net	3,767	4,272
Total natural gas resource costs	325,651	218,044
Total resource costs	$ 669,596	$ 519,002

Power purchased increased $41.4 million compared to 2004 due to an increase in the:

- price of power purchases (increased costs $35.4 million) reflecting overall increases in the wholesale energy markets, and
- volume of power purchases (increased costs $6.0 million) consistent with the increase in retail and wholesale sales, partially offset by an increase in thermal generation.

Net amortization of deferred power costs was $24.2 million for 2005 compared to $23.0 million for 2004. During 2005, we recovered (collected as revenue) $26.5 million of previously deferred power costs in Washington and $5.7 million in Idaho. There was a decrease in the recovery of previously deferred power costs in Idaho, which was primarily due to the reduction in our PCA rate surcharge. During 2005, we deferred $4.1 million of power costs in Washington and $3.9 million in Idaho. There was a decrease in the deferral of power costs due to lower actual electric resource costs as compared to the amount included in base rates in 2005 as compared to 2004.

Fuel for generation increased $54.6 million due to an increase in fuel prices and greater use of thermal generation. Our thermal generation increased 52 percent primarily due to the acquisition of the remaining interest in Coyote Springs 2.

Other fuel costs decreased $36.0 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. Our revenues from selling the natural gas exceeded other fuel costs in 2005. We account for this excess revenue under the ERM in Washington and the PCA in Idaho. The decrease in other fuel costs was primarily due to a greater percentage of fuel used in our generation.

Other electric resource costs for 2005 decreased $14.3 million compared to 2004 primarily due to the disallowance of $12.0 million of deferred power costs in our 2004 Idaho general rate case.

The expense for natural gas purchased for sale to customers increased $109.9 million due to an increase in:

- the cost of natural gas (increased costs $54.5 million), and
- total therms purchased (increased costs $55.4 million) consistent with an increase in wholesale sales as part of the balancing of loads and resources with our natural gas procurement process.

During 2005, we deferred $13.9 million of natural gas costs compared to $12.1 million for 2004. The increase reflects higher natural gas prices, partially offset by increased natural gas rates to recover 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.

Our earnings from Avista Energy are derived from the following activities:

- taking speculative positions on future price movements within established risk management policies,
- optimizing generation assets owned by other entities,
- capturing price differences between commodities (spark spread) by converting natural gas into electricity through the power generation process,
- purchasing and storing natural gas for later sales to seek gains from seasonal price variations and demand peaks,
- transmitting electricity and transporting natural gas between locations, including moving energy from lower priced/ demand regions to higher priced/demand markets and hub locations, and
- marketing natural gas to end-user industrial and commercial customers.

Our subsidiary, 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):

	2006	2005	2004
Net realized gains	$ 31,904	$ 40,142	$ 39,520
Net unrealized gains (losses)	1,510	(38,126)	(678)
Total gross margin (operating revenues less resource costs)	$ 33,414	$ 2,016	$ 38,842

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. See detailed discussion below. 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.

Total assets for the Energy Marketing and Resource Management segment decreased $995.2 million from December 31, 2005 to December 31, 2006 primarily as a result of the decrease in commodity prices (particularly natural gas) and the effect on Avista Energy's derivative commodity assets.

Overall segment results for 2005 compared to 2004

The Energy Marketing and Resource Management segment had a net loss of $8.6 million for 2005 compared to net income of $9.7 million for 2004. The net loss was primarily due to changes in natural gas prices relative to the positions that we had taken in the natural gas market. While our portfolio was within Avista Energy's position limits and in accordance with our risk management practices, losses can and do occur when the market moves contrary to our positions, which occurred during 2005. As markets moved counter to certain contracts, we acted to adjust our position consistent with established risk management policies. This process reduced the market risk; however, it had the effect of locking in losses on certain natural gas positions during 2005.

We produced positive results on the power side of Avista Energy's business in 2005, which includes trading, marketing and managing the output and availability of generation assets owned by other entities. However, gains from the power side of Avista Energy's business were less in 2005 as compared to 2004.

Differences in the estimated market value and the required accounting for certain contracts and physical assets under management

Earnings from this segment are affected by the variability associated with the difference between the estimated market value and the required accounting for certain contracts and physical assets under management of Avista Energy as disclosed above. We manage these operations on an economic basis reflecting contracts and assets under management at estimated market value. Under SFAS No. 133, certain contracts, which are considered derivatives, economically hedge other contracts and physical assets under management, which are not considered derivatives. Our derivative contracts are generally recorded at estimated market value. Our non-derivative contracts are generally accounted for at the lower of cost or market value. The accounting treatment does not affect the underlying cash flows or economics of our transactions. This difference between the estimated market value and the required accounting are generally reversed in future periods when market values change or when our contracts are settled or realized. However, the amount of the difference could increase or decrease prior to settlement due to changes in forward market prices. This primarily relates to our management of natural gas inventory and our control of natural gas-fired generation through a power purchase agreement.

We are affected by earnings variability associated with Avista Energy's economic management of natural gas inventory. Generally, injections of natural gas into storage take place in the summer months and natural gas is withdrawn from inventory in the winter months. We economically hedge the value of natural gas inventory with financial and physical sales, effectively locking in a margin on the natural gas inventory. However, accounting rules require that we account for the natural gas inventory at the lower of cost or market, while we account for our forward sales contracts to sell the natural gas (that are derivatives) at estimated market value using forward price curves. Changes in forward price curves result in income or losses on the derivative sales contracts, but generally do not affect the recorded value for natural gas inventory. Therefore, if we enter into a forward contract to sell natural gas as an economic hedge against the value of our natural gas inventory, and market prices subsequently increase, a loss for the forward contract is recorded in net income. While the market value of our natural gas inventory has also increased, the natural gas inventory remains recorded at the lower of cost or market value.

We control natural gas-fired generation through Avista Energy's power purchase agreement related to the Lancaster Project. Under the power purchase agreement, we have the right to purchase natural gas for generation, and convert to electricity for a fixed fee. We economically hedge the value of this power purchase agreement by entering into contracts to buy and sell natural gas and electricity during certain time periods in the future. Although the power purchase agreement is not a derivative and not marked-to-market, the contracts to buy and sell natural gas and electricity are derivatives that are recorded at estimated market value. Where possible, we have designated the natural gas and electricity contracts as accounting hedges in accordance with SFAS No. 133 to reduce the earnings variability associated with these combinations of accounting treatments. However, not all of our contracts qualify for hedge accounting. We will continue to recognize changes in the fair value of those contracts in earnings as unrealized gains and losses. In addition, the ineffective portion of the change in the forward value of qualifying hedges will continue to be recognized in earnings. Similar to natural gas inventory, we economically manage the power purchase agreement as if it is recorded at estimated market value.

There are other circumstances in which the difference between derivative and non-derivative accounting has an effect on Avista Energy's earnings, which have not been as significant as those described above. However, these items could become more significant in the future and we could enter into new contracts and agreements that could result in significant differences in future periods.

Analysis of operating revenues, resource costs and gross margin 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.

Analysis of operating revenues, resource costs and gross margin for 2005 compared to 2004

Operating revenues from this segment decreased $108.2 million and resource costs decreased $71.4 million for 2005 as compared to 2004 resulting in a decrease in our gross margin of $36.8 million.

Operating revenues decreased primarily due to decreased:

- revenues under the Agency Agreement with Avista Utilities as natural gas procurement operations were transitioned to Avista Utilities effective April 1, 2005, and
- net trading margin on contracts accounted for under SFAS No. 133.

These decreases were partially offset by increased revenues for Avista Energy Canada.

Resource costs decreased primarily due to decreased resource costs under the Agency Agreement with Avista Utilities, partially offset by increased resource costs for Avista Energy Canada.

Our gross margin (operating revenues less resource costs) from Avista Energy was $2.0 million for 2005 compared to $38.8 million for 2004. The decrease was primarily due to:

- the increase in natural gas prices and the resulting impact on our natural gas positions, and
- unfavorable movements in power prices also had a negative effect on our gross margin for 2005 as compared to 2004.

Our net realized gains from Avista Energy increased to $40.1 million for 2005 from $39.5 million for 2004. The slight increase in net realized gains was due to increased net gains on settled financial transactions and physical electric transactions, partially offset by increased:

- net losses on physical natural gas transactions, and
- transmission and transportation fees.

The total mark-to-market adjustment from this segment was a net unrealized loss of $38.1 million for 2005 compared to a net unrealized loss of $0.7 million for 2004. The net unrealized loss for 2005 was primarily due to realization of physical electric transactions and price movements that were unfavorable to our positions.

Energy trading activities and positions

The following table summarizes information for our trading activities at Avista Energy during 2006 (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, 2005	$ 18,682	$ 15,769	$ 34,451
Less contracts settled during 2006 (1)	(55,579)	26,089	(29,490)
Fair value of new contracts when entered into during 2006 (2)	-	-	-
Change in fair value due to changes in valuation techniques (3)	-	-	-
Change in fair value attributable to market prices and other market changes	70,941	(42,365)	28,576
Fair value of contracts as of December 31, 2006	$ 34,044	$ (507)	$ 33,537

(1) Contracts settled during 2006 include those contracts that were open in 2005 but settled during 2006 as well as new contracts entered into and settled during 2006. Amount represents net realized gains associated with these settled transactions.

(2) We did not enter into any origination transactions during 2006 in which we recognized any dealer profit or mark-to-market gain or loss at inception.

(3) During 2006, we did not experience a change in fair value due to changes in valuation techniques.

The following table discloses summarized information related to valuation techniques and contractual maturities of our energy commodity contracts at Avista Energy outstanding as of December 31, 2006 (dollars in thousands):

	Less than one year	Greater than one and less than three years	Greater than three and less than five years	Greater than five years	Total
Electric assets (liabilities), net					
Prices from other external sources (1)	$ 26,210	$ 27,288	$ -	$ -	$ 53,498
Fair value based on valuation models (2)	(1,199)	(963)	1,128	(18,420)	(19,454)
Total electric assets (liabilities), net	$ 25,011	$ 26,325	$ 1,128	$ (18,420)	$ 34,044
Natural gas assets (liabilities), net					
Prices from other external sources (1)	$ (1,017)	$ (4,213)	$ -	$ -	$ (5,230)
Fair value based on valuation models (3)	6,232	(1,387)	(122)	-	4,723
Total natural gas assets (liabilities), net	$ 5,215	$ (5,600)	$ (122)	$ -	$ (507)

(1) We determined fair value based upon actively traded, "over-the-counter" market quotes received from third party brokers. These market quotes are used through 36 months.

(2) Represents contracts for delivery at basis locations not actively traded in the "over-the-counter" markets. In addition, this includes all contracts with a delivery period greater than 36 months, for which active quotes are not available. Our internally developed market curves are determined using a production cost model with inputs for assumptions related to power prices (including, without limitation, natural gas prices, generation on- line, transmission constraints, future demand and weather). We perform frequent stress tests on the valuation of the portfolio. While consistent valuation methodologies and updates to the assumptions are used to capture current market information, changes in these methodologies or underlying assumptions could result in significantly different fair values and income recognition. These same pricing techniques and stress tests are used to evaluate a contract prior to taking a position.

(3) Represents contracts for delivery at basis locations not actively traded in the "over-the-counter" markets. In addition, this includes all contracts with a delivery period greater than 36 months, for which active quotes are not available. Our internally developed market curves are based upon published New York Mercantile Exchange prices, as well as basis spreads using historical and broker estimates.

Avista Power

Rathdrum Power, LLC (RP LLC), an unconsolidated entity that was 49 percent owned by Avista Power, LLC, operates a 270 MW natural gas-fired combined cycle combustion turbine plant in northern Idaho. In October 2006, Avista Power completed the sale of its investment in RP LLC for close to book value.

ADVANTAGE IQ

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. Advantage IQ has over 370 customers representing 200,000 billed sites in North America. The number of billed sites increased by 25,000, or 14 percent, from December 31, 2005. 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.

2005 compared to 2004
Net income for Advantage IQ was $3.9 million for 2005 compared to $0.6 million for 2004. Operating revenues increased $8.3 million and operating expenses increased $3.1 million as compared to 2004. The increase in operating revenues was primarily due to the expansion of Advantage IQ's customer base. The number of billed sites increased by 33,000, or 24 percent, in 2005. The increase in operating expenses over 2004 primarily reflects increased labor costs necessary to serve an expanding customer base, partially offset by increased efficiencies and the settlement of an employment contract during 2004. Advantage IQ's average cost of processing a bill decreased 6 percent for 2005 as compared to 2004.

OTHER BUSINESS SEGMENT

2006 compared to 2005
The net loss from this business segment 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 segment results, the improvement for AM&D was offset by:
- the accrual for an environmental liability in the first quarter of 2006,
- an increase in the loss on certain investments in this segment not related to AM&D, and
- certain income tax adjustments recorded during the third quarter of 2006.

2005 compared to 2004
The net loss from this business segment was $2.6 million for 2005 compared to a net loss of $7.2 million (excluding the cumulative effect of accounting change) for 2004. The decrease in the net loss was primarily due to the following items recorded in 2004:
- impairment of goodwill at AM&D,
- write-off of an investment in a natural gas storage project,
- accrual of environmental liabilities at Avista Development, and
- Avista Capital's purchase of Advantage IQ preferred stock at a premium.

Operating revenues increased $1.4 million and operating expenses decreased $3.6 million. The net loss for AM&D was $0.8 million for 2005 compared to $1.0 million for 2004 (excluding the impairment of goodwill).

NEW ACCOUNTING STANDARDS

Effective January 1, 2006, we adopted SFAS No. 123R, "Share-Based Payment," which requires that 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 adopted SFAS No. 123R using the modified prospective method and, accordingly, financial statement amounts for prior periods presented have not been restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. For 2006, we recorded $4.0 million (pre-tax) of stock-based compensation expense, which is included in other operating expenses in the Consolidated Statements of Income. As a result of implementing SFAS No. 123R, our income before income taxes increased $1.5 million and net income increased $1.0 million as compared to the amounts that we would have recorded for stock-based compensation expense under prior accounting rules. The impact on basic and diluted earnings per share was an increase of $0.02 per share. We expect to recognize total stock-based compensation expense (pre-tax) of $2.3 million in 2007, $1.3 million in 2008, $0.3 million in 2009 and $0.2 million in 2010 for stock-based awards granted to employees before December 31, 2006. For further information see Notes 1, 2 and 24 of the Notes to Consolidated Financial Statements.

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 will be required to adopt FIN 48 in the first quarter of 2007. We do not expect the adoption of FIN 48 to have a material effect on our financial condition and results of operations.

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 are evaluating the impact SFAS No. 157 will have on our financial condition and results of operations.

As of December 31 2006, we 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)." SFAS No. 158 required us to recognize the overfunded or underfunded status of defined benefit postretirement plans on our Consolidated Balance Sheet. This status is measured as the difference between the fair value of plan assets and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plans, the benefit obligation is the accumulated postretirement benefit obligation. Previously, we only recognized the underfunded status of defined benefit pension plans as the difference between the fair value of plan assets and the accumulated benefit obligation. As we have historically recovered and currently recover pension and other postretirement benefit costs related to our regulated operations in retail rates, we have recorded a regulatory asset for that portion of our pension and other postretirement benefit funding deficiency. As such, the underfunded status of our pension and other postretirement benefit plans under SFAS No. 158 has 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 $3.8 million (net of taxes of $2.1 million), and
- the removal of the intangible pension asset of $3.7 million (was included in other deferred charges).

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

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," which addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB No. 108 requires us to quantify misstatements using a balance sheet and income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. The adoption of SAB No. 108 in the fourth quarter of 2006 did not have any effect on our results of operations or financial condition.

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 has been elected would be reported in net income. We will be required to adopt SFAS No. 159 in 2008. We are evaluating the impact SFAS No. 159 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,
- weather (degree days), 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.

Avista Utilities 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, which we record on our Consolidated Balance Sheets, are sensitive to market price fluctuations that can occur on a daily basis.

Avista Energy Revenues and Trading Activities

Our subsidiary, Avista Energy, accounts for derivative commodity instruments under SFAS No. 133. These derivatives are marked to estimated fair market value on a daily basis (mark-to-market accounting), which causes variability in earnings. Changes in the market value of outstanding electric, natural gas and related derivative commodity instruments are recognized as unrealized gains or losses in non-utility energy marketing and trading revenues in our Consolidated Statements of Income in the period of change. We use available market prices to determine the value of electric, natural gas and related derivative commodity instruments, which are reported as assets and liabilities on our Consolidated Balance Sheets. These market prices are used through 36 months. For longer-term positions and certain short-term positions for which market prices are not available, we use models to estimate market values. Our models incorporate a variety of estimates and assumptions, the ultimate outcomes of which are beyond our control including, among others, estimates

and assumptions as to:
- demand growth,
- fuel price escalation,
- availability of existing generation, and
- costs of new generation.

Actual experience can vary significantly from these estimates and assumptions.

Avista Energy has implemented hedge accounting in accordance with SFAS No. 133. Specific natural gas and electric trading derivative contracts have been designated as hedging instruments in cash flow hedging relationships. The hedge strategies represent cash flow hedges of the variable price risk associated with expected purchases of natural gas and sales of electricity. Our designated hedging instruments represent hedges of variable price exposures generated from certain contracts, which do not qualify as derivatives under SFAS No. 133. For all derivatives designated as cash flow hedges, we document the:
- relationship between the hedging instrument and the hedged item (forecasted purchases and sales of power and natural gas), and
- risk management objective and strategy for using the hedging instrument.

We assess whether a change in the value of the designated derivative is highly effective in achieving offsetting cash flows attributable to the hedged item, both at the inception of the hedge and on an ongoing basis. Changes in the fair value of the designated derivative that are effective are recorded in accumulated other comprehensive income or loss. Changes in fair value that are not effective are recognized in earnings as operating revenues. We recognize amounts recorded in accumulated other comprehensive income or loss in earnings during the period that the hedged items are recognized in earnings.

Pension Plans and Other Postretirement Benefit Plans

We have a defined benefit pension plan covering substantially all regular full-time employees at Avista Utilities and Avista Energy. As of December 31, 2006, the fair value of our pension plan assets was less than the present value of the projected benefit obligation under the plan. See "New Accounting Standards" and "Note 2 of the Notes to Consolidated Financial Statements" for further information.

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 $14.5 million for 2006, $13.4 million for 2005 and $14.9 million for 2004. 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 2006, 2005 and 2004 that have had any significant effect on our recorded pension plan amounts. We have revised the key assumption of the discount rate in 2006 and 2004 and the key assumption of the expected long-term return on assets in 2005. Such changes had an effect on our pension costs in 2006, 2005 and 2004 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 discount rate in 2006 to 6.15 percent from 5.75 percent, which was used in 2005 and 2004 for estimating the benefit obligation. We reduced the discount rate in 2004 to 5.75 percent from 6.25 percent.

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 2006 and 2005, and 8 percent in 2004. The actual return on plan assets, net of fees, was a gain of $25.2 million (or 12.6 percent) for 2006, $11.3 million (or 6.1 percent) for 2005 and $16.1 million (or 10.4 percent) for 2004. 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%	$ -*	$ 1,000
Expected long-term return on plan assets	+0.5%	-*	(1,000)
Discount rate	-0.5%	22,106	2,153
Discount rate	+0.5%	(19,828)	(1,955)

* *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, 2006 by $1.4 million and the service and interest cost by $0.1 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, 2006 by $1.2 million and the service and interest cost by $0.1 million.

Stock-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123R, which requires that 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 is estimated on the date of grant using a Monte Carlo valuation model. 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 has been 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 have been met, liabilities have been accrued or assets have been written 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 2006, positive cash flows from operating activities of $201.5 million, proceeds from the issuance of long-term debt of $149.8 million and funds from the issuance of common stock of $88.6 million were used to fund the majority of our cash requirements. These cash requirements included utility capital expenditures of $161.3 million, debt redemptions and maturities of $199.0 million and dividends of $27.9 million. As cash flows from operating activities and other sources of cash inflows exceeded other funding requirements, our total debt decreased $112.5 million during 2006.

Operating Activities

Net cash provided by operating activities was $201.5 million for 2006 compared to $130.2 million for 2005. Net cash provided by working capital components was $16.5 million for 2006, compared to net cash used of $57.5 million for 2005. 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).

The net cash used during 2005 primarily reflected an increase in accounts receivable and cash deposits with counterparties (representing cash deposited as collateral funds at Avista Energy), partially offset by a net increase in the balance outstanding under our revolving accounts receivable sales facility, and an increase in accounts payable. The $28.7 million increase in deposits with counterparties in 2005 was due to high natural gas prices and the posting of cash collateral for margin requirements in addition to letters of credit issued under our credit line at Avista Energy. The significant increase in accounts receivable and accounts payable in 2005 was primarily due to an increase in energy commodity prices, as well as increased natural gas wholesale sales and purchases at the utility.

Significant non-cash items included $56.3 million of power and natural gas cost amortizations, net of deferrals, for 2006, an increase from $9.6 million for 2005 primarily due to an increase in recoveries of previously deferred costs from customers. Significant changes in non-cash items also included a $39.6 million change in energy commodity assets and liabilities, representing the change to an unrealized gain of $1.5 million on energy trading activities for 2006 as compared to an unrealized loss of $38.1 million for 2005. There was also a significant change in the provision for deferred income taxes to a benefit of $19.1 million for 2006 from an expense of $8.9 million for 2005. This is reflected through higher income tax payments, which increased to $63.4 million for 2006, compared to $26.4 million for 2005.

Investing Activities
Net cash used in investing activities was $139.7 million for 2006, a decrease compared to $199.3 million for 2005. This was primarily due to a decrease in utility property capital expenditures, which included $57.5 million for the purchase of Coyote Springs 2 in 2005. Investing activities for 2006 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 RP LLC and a turbine at Avista Power). During 2005, we received $17.2 million from asset sales (primarily the sale of our South Lake Tahoe natural gas properties).

Financing Activities
Net cash used in financing activities was $59.4 million for 2006 compared to net cash provided of $6.6 million for 2005. During 2006, our short-term borrowings decreased $59.5 million, which primarily reflects a decrease in the amount of debt outstanding under our $320.0 million 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, we had debt redemptions and maturities of $199.0 million. Cash dividends paid increased to $27.9 million (or 57 cents per share) for 2006 from $26.4 million (or 54.5 cents per share) for 2005. 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.

During 2005, short-term borrowings decreased $5.0 million, which reflects a decrease in the amount of debt outstanding under our committed line of credit. In the fourth quarter of 2005, we issued $150.0 million (net proceeds of $149.6 million) of 6.25 percent First Mortgage Bonds due in 2035. During 2005, we redeemed a total of $26.0 million of medium-term notes scheduled to mature in future years, repaid $54.6 million of WP Funding LP debt and $31.0 million of long-term debt matured.

OVERALL LIQUIDITY

Our consolidated operating cash flows are primarily derived from the operations of Avista Utilities and Avista Energy. 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. The primary source and use of operating cash flows for Avista Energy is 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 include other operating expenses and taxes.

Our operating cash flows do not always fully support the needs for utility capital expenditures. As such, from time to time, we may 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 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.

The general rate increases implemented at the utility since 2002 have improved our operating cash flows from regulated operations. In December 2005, the WUTC approved a settlement agreement (with certain conditions) related to our Washington general rate case that provided for electric and natural gas base rate increases. In December 2006, the WUTC dismissed our request to increase electric rates for Washington customers. We will continue to periodically file for rate adjustments for recovery of operating costs and capital investments and to provide opportunity to align our earned returns with those allowed by regulators. 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 are buying 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,
- outages at generating facilities, and
- failure of third parties to deliver on energy or capacity contracts.

Our hydroelectric generation was 104 percent of normal in 2006. Our hydroelectric generation has been below normal (based on a 70-year average) for five of the past seven years. For 2007, we are forecasting hydroelectric generation to be normal. This 2007 forecast will change based upon precipitation, temperatures and other variables during the year.

We monitor the potential liquidity impacts of increasing energy commodity prices for both our utility operations (Avista Utilities) and our energy marketing and resource management operations (Avista Energy). We believe that we have adequate liquidity to meet the increased cash needs of higher energy commodity prices through our:

- current cash and cash equivalents,
- $320.0 million committed line of credit at Avista Corp. (Avista Utilities), and
- $145.0 million committed line of credit at Avista Energy.

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, 2006 and 2005 (dollars in thousands):

	December 31, 2006		December 31, 2005	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 26,605	1.3%	$ 39,524	2.0%
Short-term borrowings	4,000	0.2	63,494	3.2
Long-term debt to affiliated trusts	113,403	5.6	113,403	5.6
Long-term debt	949,854	46.6	989,990	49.4
Total debt	1,093,862	53.7	1,206,411	60.2
Preferred stock-cumulative (including current portion)	26,250	1.3	28,000	1.4
Total liabilities	1,120,112	55.0	1,234,411	61.6
Stockholders' equity	916,846	45.0	771,128	38.4
Total	$ 2,036,958	100.0%	$ 2,005,539	100.0%

Our total debt decreased $112.5 million during 2006 primarily due to:

- the payment of a portion of maturing debt with operating cash flows and other sources of funds,
- operating cash flows in excess of other funding requirements,
- a decrease in the amount outstanding on our committed line of credit, and
- the issuance of common stock as part of the funds were used to repay short-term borrowings.

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. Our stockholders' equity increased $145.7 million during 2006 primarily due to the issuance of common stock, net income and other comprehensive income, partially offset by dividends.

We generally fund capital expenditures with a combination of internally generated cash and external financing. The level of cash generated internally and the amount that is available for capital expenditures fluctuates depending on a variety of factors. Cash provided by our utility operating activities and cash generated by Avista Energy are expected to be the primary sources of funds for operating needs, dividends, capital expenditures, as well as maturing long-term debt and preferred stock for 2007. Borrowings under our $320.0 million committed line of credit may supplement these funds to the extent necessary.

We have $370 million of long-term debt maturities and mandatory preferred stock redemptions in 2007 and 2008. Our forecasts indicate that we will need to issue new 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.

On April 6, 2006, we amended our committed line of credit agreement with various banks to lower bank fees and borrowing costs. The committed line of credit was originally entered into on December 17, 2004. Amendments to our committed line of credit included a reduction in the total amount of the facility to $320.0 million from $350.0 million and an extension of the expiration date to April 5, 2011 from December 16, 2009. We chose to reduce the total amount of the facility based on our forecasted liquidity needs. Under the amended credit agreement, we can request the issuance of up to $320.0 million in letters of credit, an increase from $150.0 million prior to the amendment. As of December 31, 2006, we had $4.0 million of borrowings outstanding, a decrease from $63.0 million as of December 31, 2005. As of December 31, 2006, there were $77.1 million in letters of credit outstanding, an increase from $44.1 million as of December 31, 2005. The amended 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 amended 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, 2006, we were in compliance with this covenant with a ratio of 2.56 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. Under the amendment, this ratio limitation will be increased to 75 percent during the period between the completion of the proposed change in our corporate organization (see Note 26) and December 31, 2007. As of December 31, 2006, we were in compliance with this covenant with a ratio of 53.7 percent. If the proposed change in organization becomes effective, the committed line of credit agreement will remain at Avista Corp. (Avista Utilities).

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, 2006, 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, 2006, we could issue $651.9 million of additional preferred stock at an assumed dividend rate of 6.95 percent with a maturity date later than June 1, 2008.

The Mortgage and Deed of Trust securing our First Mortgage Bonds (including Secured Medium-Term Notes) contains limitations on the amount of First Mortgage Bonds that we may issue based on, among other things, a 70 percent debt-to-collateral ratio, and/or retired First Mortgage Bonds, and a 2 to 1 net earnings to First Mortgage Bond interest ratio. As of December 31, 2006, we could issue $429.5 million of additional First Mortgage Bonds under the Mortgage and Deed of Trust.

As further discussed at "Avista Utilities - Regulatory Matters," 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 implementation of our holding company structure. One of the conditions provides for the same utility equity components that are required in our 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 have also entered into a settlement agreement in Washington related to our proposed holding company formation, which is subject to approval by the WUTC. In this settlement agreement, we have 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. The utility equity component was 38.1 percent as of December 31, 2006.

In addition to expected earnings, we are implementing measures to increase our utility equity ratio. Such measures include:

- delivering original issue shares under equity compensation and dividend reinvestment plans, and
- making common stock issuances, from time to time, through underwriters or agents.

In December 2006, we issued 3,162,500 shares of common stock through an underwriter. Also, 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. As of February 26, 2007, we have not issued any shares under the 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, its subsidiaries. As of December 31, 2006, Avista Corp. held a short-term subordinated note receivable from Avista Capital in the principal amount of $7.2 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 securityholders 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 20, 2006, 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 21, 2006 to March 20, 2007. 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, 2006, we had sold $85.0 million in accounts receivable under this revolving agreement. We expect to renew this facility before the March 20, 2007 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 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 $98.7 million as of December 31, 2006) 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, 2007:

	Standard & Poor's	Moody's	Fitch, Inc.
Avista Corporation			
Corporate/Issuer rating	BB+	Ba1	BB
Senior secured debt	BBB-	Baa3	BBB-
Senior unsecured debt	BB+	Ba1	BB+
Preferred stock	BB-	Ba3	BB
Avista Capital II [1]			
Preferred Trust Securities	BB-	Ba2	BB
AVA Capital Trust III [1]			
Preferred Trust Securities	BB-	Ba2	BB
Rating outlook	Stable	Stable	Positive

(1) Only assets are subordinated debentures of Avista Corporation.

These 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, 2006, 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 2005 and 2006. We are planning to contribute $15 million to the pension plan in 2007. Our total pension plan contributions were $69 million from 2002 through 2006.

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 new funding rules could increase our minimum required cash contributions to the pension plan in the future. The legislation is effective in 2008; however, the law contains a transition period related to the funding rules. We do not expect the Pension Act to have a material effect on our financial condition, results of operations or cash flows.

DIVIDENDS

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

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

Our net income available for dividends is derived primarily from our regulated utility operations (Avista Utilities) and Avista Energy.

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 in 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, 2006, we are meeting the conditions that would allow us to increase the common stock cash dividend in excess of 5 percent over the previous quarter.

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 implementation of our holding company structure. One of the conditions requires IPUC approval of any dividend to the holding company that would reduce utility common equity below 25 percent. Furthermore, we have entered into a similar agreement with the WUTC Staff (that is subject to approval by the WUTC). This agreement would require WUTC approval of any dividend to the holding company that would reduce utility common equity below 30 percent.

Avista Energy holds a significant portion of cash and cash equivalents reflected on our Consolidated Balance Sheets. Covenants in Avista Energy's credit agreement, certain counterparty agreements and market liquidity conditions result in Avista Energy maintaining certain levels of cash and therefore effectively limit the amount of cash dividends that are available for distribution to Avista Capital and ultimately to Avista Corp. In 2006, Avista Energy paid $6.0 million in dividends to Avista Capital and Avista Capital paid a $6.0 million dividend to Avista Corp.

AVISTA UTILITIES OPERATIONS

Capital expenditures for our utility were $493.3 million for the years 2004 through 2006. During the years 2007 through 2009, we expect utility capital expenditures to be in the range of $180 million to $190 million per year. In addition to ongoing needs for our distribution system, significant projects include the continued enhancement of our transmission system and 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. Long-term debt maturities and mandatory redemptions of preferred stock are expected to total $370 million during the period from 2007 through 2009. During 2007, internally generated funds and short-term borrowing arrangements are expected to be sufficient to fund these requirements. In 2008, we will most likely need to issue additional long-term debt to fund these obligations, which include long-term debt maturities of $318 million. We have locked in the interest rate on $125 million of long-term debt issuances during 2008 through forward-starting interest rate swap agreements.

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. As outlined in our 2005 Electric Integrated Resource Plan, which we filed with regulators in Washington and Idaho, quarterly energy deficits are projected to begin in 2007 and annual energy deficits are projected to begin in 2010. To help meet forecasted increases in electric loads, we issued a request for proposals in January 2006 to consider adding 35 average megawatts of long-term renewable energy supplies. In 2006, we entered into an agreement with Idaho Power to jointly investigate possible future coal-based generation resources. Future generation resource decisions may be impacted by potential legislation for restrictions on greenhouse gas emissions as discussed at "Environmental Issues and Other Contingencies."

As of December 31, 2006, we had $2.4 million of restricted cash at Avista Corp. /Avista Utilities. The restricted cash relates to deposits for interest rate swap agreements.

Our utility held cash deposits from other parties in the amount of $39.4 million as of December 31, 2006, which is included in deposits from counterparties on the Consolidated Balance Sheet. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral.

See "Notes 4, 14, 15, 16, 17, 20, 21 and 22 of Notes to Consolidated Financial Statements" for additional details related to our financing activities.

ENERGY MARKETING AND RESOURCE MANAGEMENT (AVISTA ENERGY) OPERATIONS

Our subsidiary, Avista Energy, and its subsidiary, Avista Energy Canada, as co-borrowers, have a committed credit agreement with a group of banks in the aggregate amount of $145.0 million with an expiration date of July 12, 2007. Avista Energy is currently evaluating renewal of its credit facility and anticipates it will be in place by the July 12, 2007 expiration date of the current credit agreement. This committed credit facility provides for the issuance of letters of credit to secure contractual obligations to counterparties and for cash advances. This facility is secured by the assets of Avista Energy and Avista Energy Canada and guaranteed by Avista Capital and by CoPac Management, Inc., a wholly owned subsidiary of Avista Energy Canada. The maximum amount of credit extended by the banks for the issuance of letters of credit is the subscribed amount of the facility less the amount of outstanding cash advances, if any. The maximum amount available for cash advances under the credit agreement is $50.0 million. No cash advances were outstanding as of December 31, 2006. Letters of credit in the aggregate amount of $52.5 million were outstanding as of December 31, 2006. The cash deposits of Avista Energy at the respective banks collateralized $24.9 million of these letters of credit as of December 31, 2006, which is reflected as restricted cash on our Consolidated Balance Sheets.

Avista Energy's credit agreement contains covenants and default provisions, including covenants to maintain "minimum net working capital" and "minimum net worth," as well as a covenant limiting the amount of indebtedness that the co-borrowers may incur. The credit agreement also contains covenants and other restrictions related to the co-borrowers' trading limits and positions, including VAR limits, restrictions with respect to changes in risk management policies or volumetric limits, and limits on exposure related to hourly and daily trading of electricity. These covenants, certain counterparty agreements and market liquidity conditions result in Avista Energy maintaining certain levels of cash and therefore effectively limit the amount of cash dividends that are available for distribution to Avista Capital and ultimately to Avista Corp. Avista Energy was in compliance with the covenants of its credit agreement as of December 31, 2006.

Avista Capital provides guarantees for Avista Energy's credit agreement (see discussion above) and, in the course of business, may provide performance guarantees to other parties with whom Avista Energy may be doing business. At any point in time, Avista Capital is only liable for the outstanding portion of the performance guarantee, which was $27.5 million as of December 31, 2006. The face value of all performance guarantees issued by Avista Capital for energy trading contracts at Avista Energy was $362.4 million as of December 31, 2006.

As part of its cash management practices and operations, Avista Energy from time to time makes unsecured short-term loans to its parent, Avista Capital. Avista Capital's Board of Directors has limited the total outstanding indebtedness to no more than $45.0 million. Further, as required under Avista Energy's credit facility, such loans cannot be outstanding longer than 90 days without being repaid. During 2006, Avista Energy's maximum total outstanding short-term loan to Avista Capital was $35.5 million. As of December 31, 2006, all outstanding loans including accrued interest had been repaid.

Avista Energy manages collateral requirements with counterparties by providing letters of credit, providing guarantees from Avista Capital, depositing cash with counterparties and offsetting transactions with counterparties. Cash deposited with counterparties totaled $79.5 million as of December 31, 2006, an increase from $59.4 million as of December 31, 2005. Avista Energy held cash deposits from other parties in the amount of $2.1 million as of December 31, 2006, which is included in deposits from counterparties on our Consolidated Balance Sheet. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of collateral.

Capital expenditures for the Energy Marketing and Resource Management segment were $4.1 million for the years 2004 through 2006. We do not expect capital expenditures for this segment to be significant to our consolidated cash flows and financial condition during the years 2007 through 2009.

As of December 31, 2006, Avista Energy had $29.6 million in cash, as well as $27.5 million of restricted cash.

ADVANTAGE IQ OPERATIONS

Capital expenditures for Advantage IQ were $4.6 million for the years 2004 through 2006. Although capital expenditures increased in 2006, we do not expect capital expenditures for the years 2007 through 2009 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, 2006, Advantage IQ had $0.9 million of debt outstanding related to capital leases.

OTHER OPERATIONS

Capital expenditures for these companies were $2.3 million for the years 2004 through 2006. We do not expect capital expenditures for the years 2007 through 2009 in this segment to be significant to our consolidated cash flows and financial condition.

As of December 31, 2006, this business segment had $5.8 million of long-term debt outstanding.

CONTRACTUAL OBLIGATIONS

The following table provides a summary of our future contractual obligations as of December 31, 2006 (dollars in millions):

	2007	2008	2009	2010	2011	Thereafter
Avista Utilities:						
Long-term debt maturities (1)	$ 26	$ 318	$ -	$ 35	$ -	$ 591
Long-term debt to affiliated trusts (1)	-	-	-	-	-	113
Interest payments on long-term debt (2)	76	58	45	44	42	797
Short-term borrowings (3)	4	-	-	-	-	-
Accounts receivable sales (4)	85	-	-	-	-	-
Preferred stock redemptions (1)	26	-	-	-	-	-
Energy purchase contracts (5)	326	200	187	161	131	1,183
Public Utility District contracts (5)	4	4	4	3	3	28
Operating lease obligations (6)	1	1	1	-	-	3
Other obligations (7)	15	15	16	16	16	197
Information services contracts	12	13	13	13	14	14
Pension plan funding (9)	15	15	15	15	-	-
Avista Capital (consolidated):						
Long-term debt	-	-	-	-	-	6
Energy purchase contracts (8)	398	257	213	196	36	370
Operating lease obligations (6)	3	3	3	1	-	-
Total contractual obligations	$ 991	$ 884	$ 497	$ 484	$ 242	$ 3,302

(1) For 2007, we expect that cash flows from operations and short-term debt will provide sufficient funds for maturing long-term debt and preferred stock redemptions. In 2008, we will most likely need to issue additional long-term debt to fund 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, 2006.

(3) Represents $4 million outstanding under 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) Represents 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. Avista Energy also has sales commitments related to these contractual obligations in future periods.

(9) Represents our estimated cash contributions to the pension plan through 2010. We cannot reasonably estimate pension plan contributions beyond 2010 at this time.

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

Our operations are exposed to risks including, but not limited to:

- market prices and supply of wholesale energy, which we purchase and sell, including power, fuel and natural gas,
- regulatory allowance of the recovery of power and natural gas costs, operating costs and capital investments,
- streamflow and weather conditions,
- the effects of changes in legislative and governmental regulations,
- changes in regulatory requirements,
- availability of generation facilities,
- competition,
- technology, and
- availability of funding.

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, which provide for recovery of the majority of the changes in our power and natural gas costs. The majority of power and natural gas costs that exceed 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 104 percent of normal in 2006. Our hydroelectric generation has been below normal (based on a 70-year average) for five of the past seven years. We cannot determine if lower than normal hydroelectric generation will continue in future years. For 2007, we are forecasting hydroelectric generation to be normal. This 2007 forecast will change based upon precipitation, temperatures and other variables during the year. The earnings impact of these factors is mitigated by regulatory mechanisms that are intended to defer increased power supply costs for recovery in future periods. 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."

During recent years, natural gas prices have been volatile with a general upward trend. We continue to be concerned about the impact that increasing rates have on our customers, which could reduce future demand for natural gas. However, market prices for natural gas continue to be competitive compared to alternative fuel sources for residential, commercial and industrial customers. We regularly discuss our natural gas purchase and hedging strategies with regulators. We believe that natural gas should sustain its market advantage over competing energy sources based on the levels of existing reserves and the potential for 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.

Our natural gas business faces the potential for certain natural gas customers to by-pass our natural gas system. 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.

In addition to asset management activities, our subsidiary, Avista Energy, trades electricity and natural gas, along with derivative commodity instruments. These instruments include futures, options, swaps and other contractual arrangements. As a result of these trading activities, we are subject to various risks including commodity price risk and credit risk, as well as possible risks resulting from the imposition of market controls by federal and state agencies.

The FERC is conducting proceedings and investigations related to market controls within the western United States that include proposals by certain parties to impose refunds. As a result, 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, 2006, 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

Commodity price risk is, in general, the risk of 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 retail loads.

Electricity prices are affected by a number of factors, including:

- 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,
- demand for natural gas as fuel for electric generation,
- global energy markets,
- availability of pipeline capacity to transport natural gas from region to region, and
- oil prices.

Demand changes caused by variations in the weather and other factors can also affect market prices for electricity and natural gas. 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. The FERC imposed a price mitigation plan in the western United States in June 2001 and has subsequently modified various price and market control regulations.

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 risk of loss that we would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy or make financial settlements. We often extend credit to counterparties and customers and are exposed to the risk that we may not be 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 replace existing contracts with contracts at then-current market prices or to honor the underlying commitment.

We seek to mitigate credit risk by:

- applying specific eligibility criteria to existing and prospective counterparties, and
- actively monitoring current credit exposures.

These 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,
- natural gas distribution companies, 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,
- cash deposits, and
- parent company performance guarantees (only pertains to Avista Capital guarantees of Avista Energy).

In periods of price volatility, the level of exposure can change significantly. 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.

In conjunction with the valuation of our commodity derivative instruments and accounts receivable, we maintain credit reserves that are based on the evaluation of the credit risk of the overall portfolio. Based on these 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:

- increases or decreases in load demand,
- blackouts or disruptions to our transmission or transportation systems,
- fuel quality and availability,
- forced outages at generating plants,
- disruptions to information systems and other administrative tools 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 threats, both domestic and foreign, 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. 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, 2006, we had a derivative liability of $5.1 million and provided cash collateral of $2.4 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, 2006 would have decreased this derivative liability by $0.9 million, while a 10-basis-point decrease would have increased the liability by $0.9 million.

Foreign Currency Risk

A significant portion of Avista Utilities' 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. The utility does 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.

Avista Energy has investments in Canadian companies through Avista Energy Canada and its subsidiary, CoPac Management, Inc. In addition, Avista Energy enters into Canadian dollar denominated transactions in Canada for natural gas commodity and related services. These transactions in aggregate expose us to foreign currency risk. Avista Energy attempts to limit exposure to changing foreign exchange rates through both operational and financial market actions. This includes entering into forward and swap contracts to hedge existing exposures, firm commitments and anticipated transactions. These arrangements are carried at fair value and were not significant as of December 31, 2006.

RISK MANAGEMENT

Risk Policies and Oversight

In our utility operation and at Avista Energy, we use a variety of techniques to manage risks for energy resources and wholesale energy market activities. We have risk management policies and procedures to manage these risks, both qualitative and quantitative. Our Risk Management Committee establishes risk management policies and procedures and monitors compliance. The Risk Management Committee is comprised of certain officers and other individuals 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 risk management policies and procedures on a regular basis. 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.

Quantitative Risk Measurements

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 decisions 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. The balancing of loads and resources is accomplished through commodity purchases and the use of natural gas storage facilities that we own or have contracts to use. Timing, pricing and volume decisions are subject to our utility hedging practices that include a cross-departmental oversight group.

Our subsidiary, Avista Energy, measures the risk in its electric and natural gas portfolio daily utilizing a Value-at-Risk (VAR) model, which monitors its risk in comparison to established thresholds. VAR measures the expected portfolio loss under hypothetical adverse price movements, over a given time interval within a given confidence level. The VAR computations utilize historical price movements over a specified period to simulate forward price curves in the energy markets and estimate the potential unfavorable impact of price movement in the portfolio. The quantification of market risk using VAR provides a consistent measure of risk across Avista Energy's continually changing portfolio. VAR represents an estimate of reasonably possible net losses in earnings that would be recognized on our portfolio assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur. Our VAR computations utilize several key assumptions, including a 95 percent confidence level for the resultant price movement and holding periods of one and three days. The calculation includes derivative commodity instruments held for trading purposes and excludes the effects of embedded physical options in the trading portfolio. For forward transactions that settle beyond the next 12 calendar quarters, we apply other risk measurement techniques, including price sensitivity stress tests, to assess the future market risk. Volatility in longer-dated forward markets tends to be less than in near-term markets. We also measure open positions in terms of volumes at each delivery location for each forward time period. The permissible extent of open positions is included in the risk management policy and is measured with stress tests and VAR modeling.

As of December 31, 2006, Avista Energy's estimated potential one-day unfavorable impact on gross margin as measured by VAR was $0.4 million, compared to $0.8 million as of December 31, 2005. The average daily VAR for 2006 was $0.8 million. The high daily VAR was $1.8 million and the low daily VAR was $0.4 million during 2006. Avista Energy was in compliance with its one-day VAR limits during 2006. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits.

As of December 31, 2006, 91 percent of Avista Energy's credit exposure was to investment grade counterparties or non-investment grade counterparties whose exposure was mitigated through collateral posted to Avista Energy. Of the remaining unmitigated exposure to non-investment grade counterparties, 83 percent represents settlements that were made within thirty days after December 31, 2006.

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 2.0 to 2.3 percent and natural gas customer growth to average 2.8 to 3.3 percent within our service area, we anticipate retail electric and natural gas load growth will average between 3.0 and 3.5 percent annually for the four year period 2007-2010. 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 doubled 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 is providing 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 were designed to comply with all applicable environmental laws.

We monitor legislative developments at both the state and national level with respect to environmental issues, particularly those related to the potential for further restrictions on the operation of our generating plants.

Current environmental laws and regulations have, and future modifications may have, the effect of:

- increasing the lead time for the construction of new generating plants,
- requiring modification of our existing generating plants,
- 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.

Long-term global climate changes, particularly with respect to the Pacific Northwest, 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 any legislative or regulatory developments in response to global climate changes, including restrictions on the operation of our power generation resources.

We continue to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas requirements. In particular, greenhouse gas bills have been introduced in the legislature in the state of Washington and the U. S. Senate and House of Representatives. Greenhouse gas requirements, if enacted and applicable, could result in significant costs for us to comply with restrictions on carbon dioxide or other greenhouse gas emissions. Such requirements could preclude us from developing certain types of generating plants, including coal-fired plants.

Initiative Measure 937 (I-937) was passed into law through the General Election in Washington on November 7, 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) includes the acquisition of additional renewable resources such that, if the IRP is implemented, we would be compliant with the requirement by 2020 assuming that such renewable resources were cost effective. The amount of renewable resources in our future IRP's could change if the cost effectiveness of those resources changes.

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

	2006	2005	2004
Operating Revenues:			
Utility revenues	$ 1,267,938	$ 1,161,317	$ 972,574
Non-utility energy marketing and trading revenues	177,551	148,010	138,435
Other non-utility revenues	60,822	50,280	40,571
Total operating revenues	1,506,311	1,359,607	1,151,580
Operating Expenses:			
Utility operating expenses:			
Resource costs	751,646	669,596	519,002
Other operating expenses	187,161	181,478	180,418
Depreciation and amortization	81,904	80,914	72,787
Taxes other than income taxes	69,882	68,044	66,294
Non-utility operating expenses:			
Resource costs	144,137	145,994	99,593
Other operating expenses	66,546	59,653	67,378
Depreciation and amortization	5,179	5,997	5,638
Total operating expenses	1,306,455	1,211,676	1,011,110
Gain on sale of utility properties	-	4,093	-
Income from operations	199,856	152,024	140,470
Other Income (Expense):			
Interest expense	(89,051)	(86,512)	(87,265)
Interest expense to affiliated trusts	(7,116)	(6,202)	(5,782)
Capitalized interest	2,934	1,689	1,393
Other income - net	8,600	10,030	8,390
Total other income (expense)-net	(84,633)	(80,995)	(83,264)
Income before income taxes	115,223	71,029	57,206
Income taxes	42,090	25,861	21,592
Net income before cumulative effect of accounting change	73,133	45,168	35,614
Cumulative effect of accounting change, net of taxes of $(248)	-	-	(460)
Net income	$ 73,133	$ 45,168	$ 35,154
Weighted-average common shares outstanding (thousands), Basic	49,162	48,523	48,400
Weighted-average common shares outstanding (thousands), Diluted	49,897	48,979	48,886
Earnings per common share, basic (Note 23):			
Earnings before cumulative effect of accounting change	$ 1.49	$ 0.93	$ 0.74
Loss from cumulative effect of accounting change	-	-	(0.01)
Total earnings per common share, basic	$ 1.49	$ 0.93	$ 0.73
Earnings per common share, diluted (Note 23):			
Earnings before cumulative effect of accounting change	$ 1.47	$ 0.92	$ 0.73
Loss from cumulative effect of accounting change	-	-	(0.01)
Total earnings per common share, diluted	$ 1.47	$ 0.92	$ 0.72
Dividends paid per common share	$ 0.570	$ 0.545	$ 0.515

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

	2006	2005	2004
Net income	$ 73,133	$ 45,168	$ 35,154
Other Comprehensive Income (Loss):			
Foreign currency translation adjustment	(38)	268	493
Unrealized gains (losses) on interest rate swap agreements – net of taxes of $436, $605 and $(1,969), respectively	810	1,123	(3,656)
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 $4,023, $(1,444) and $(4,086), respectively	7,472	(2,681)	(7,589)
Unrealized gains (losses) on derivative commodity instruments – net of taxes of $(555), $1,693 and $(681), respectively	(1,030)	3,145	(1,264)
Reclassification adjustment for realized gains on derivative commodity instruments included in net income – net of taxes of $(294), $(898) and $(257), respectively	(546)	(1,668)	(477)
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)	9,162	(2,766)	(12,493)
Comprehensive income	$ 82,295	$ 42,402	$ 22,661

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS

Avista Corporation
As of December 31
Dollars in thousands

	2006	2005
Assets:		
Current Assets:		
Cash and cash equivalents	$ 28,242	$ 25,917
Restricted cash	29,903	25,634
Accounts and notes receivable-less allowances of $42,360 and $44,634	286,150	502,947
Energy commodity derivative assets	343,726	918,609
Utility energy commodity derivative assets	10,828	69,494
Regulatory asset for utility derivatives	62,650	-
Funds held for customers	90,134	38,269
Deposits with counterparties	79,477	59,354
Materials and supplies, fuel stock and natural gas stored	42,425	54,123
Deferred income taxes	10,932	14,519
Assets held for sale	3,543	11,850
Other current assets	44,264	49,652
Total current assets	1,032,274	1,770,368
Net Utility Property:		
Utility plant in service	2,938,456	2,847,043
Construction work in progress	103,226	64,291
Total	3,041,682	2,911,334
Less: Accumulated depreciation and amortization	826,645	784,917
Total net utility property	2,215,037	2,126,417
Other Property and Investments:		
Investment in exchange power-net	31,033	33,483
Non-utility properties and investments-net	60,301	77,731
Non-current energy commodity derivative assets	313,300	511,280
Investment in affiliated trusts	13,403	13,403
Other property and investments-net	15,594	15,058
Total other property and investments	433,631	650,955
Deferred Charges:		
Regulatory assets for deferred income tax	105,935	114,109
Regulatory assets for pensions and other postretirement benefits	54,192	-
Other regulatory assets	31,752	26,660
Non-current utility energy commodity derivative assets	25,575	46,731
Power and natural gas deferrals	97,792	147,622
Unamortized debt expense	46,554	48,522
Other deferred charges	13,766	17,110
Total deferred charges	375,566	400,754
Total assets	$ 4,056,508	$ 4,948,494

The Accompanying Notes are an Integral Part of These Statements.

CONSOLIDATED BALANCE SHEETS (CONTINUED)

Avista Corporation
As of December 31
Dollars in thousands

	2006	2005
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Accounts payable	$ 286,099	$ 511,427
Energy commodity derivative liabilities	313,499	906,794
Customer fund obligations	90,134	38,237
Deposits from counterparties	41,493	13,724
Current portion of long-term debt	26,605	39,524
Current portion of preferred stock-cumulative (see description below)	26,250	1,750
Short-term borrowings	4,000	63,494
Interest accrued	11,595	18,643
Utility energy commodity derivative liabilities	73,478	3,447
Regulatory liability for utility derivatives	-	66,047
Other current liabilities	72,056	66,801
Total current liabilities	945,209	1,729,888
Long-term debt	949,854	989,990
Long-term debt to affiliated trusts	113,403	113,403
Preferred Stock-Cumulative (subject to mandatory redemption):		
10,000,000 shares authorized: $6.95 Series K; 262,500 and 280,000 total shares outstanding at December 31, 2006 and 2005 ($100 stated value)	-	26,250
Other Non-Current Liabilities and Deferred Credits:		
Non-current energy commodity derivative liabilities	309,990	488,644
Regulatory liability for utility plant retirement costs	197,712	186,635
Non-current regulatory liability for utility derivatives	15,400	46,643
Pensions and other postretirement benefits	100,033	64,092
Deferred income taxes	461,006	488,934
Other non-current liabilities and deferred credits	47,055	42,887
Total other non-current liabilities and deferred credits	1,131,196	1,317,835
Total liabilities	3,139,662	4,177,366
Commitments and Contingencies (See Notes to Consolidated Financial Statements)		
Stockholders' Equity:		
Common stock, no par value; 200,000,000 shares authorized; 52,514,326 and 48,593,139 shares outstanding	715,620	620,598
Accumulated other comprehensive loss	(17,966)	(23,299)
Retained earnings	219,192	173,829
Total stockholders' equity	916,846	771,128
Total liabilities and stockholders' equity	$ 4,056,508	$ 4,948,494

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

	2006	2005	2004
Operating Activities:			
Net income	$ 73,133	$ 45,168	$ 35,154
Cumulative effect of accounting change	-	-	460
Purchases of securities held for trading	-	-	(15,260)
Sales of securities held for trading	-	-	34,192
Non-cash items included in net income:			
Depreciation and amortization	87,083	86,911	78,425
Provision for deferred income taxes	(19,108)	8,865	19,168
Power and natural gas cost amortizations, net of deferrals	56,327	9,630	11,087
Amortization of debt expense	7,741	7,762	8,301
Write-offs and impairments of assets	-	1,001	21,990
Energy commodity assets and liabilities	(1,510)	38,126	678
Gain on sale of utility properties	-	(4,093)	-
Other	(18,743)	(5,678)	5,163
Changes in working capital components:			
Sale of customer accounts receivable under revolving agreement-net	-	13,000	-
Accounts and notes receivable	219,071	(203,363)	(6,904)
Materials and supplies, fuel stock and natural gas stored	11,698	(10,642)	(4,023)
Deposits with counterparties	(20,123)	(28,687)	6,181
Other current assets	(46,477)	(19,801)	(16,283)
Accounts payable	(225,499)	189,115	26,909
Deposits from counterparties	27,769	7,709	(91,796)
Other current liabilities	50,104	(4,789)	5,996
Net cash provided by operating activities	201,466	130,234	119,438
Investing Activities:			
Utility property capital expenditures (excluding equity-related AFUDC)	(161,266)	(215,341)	(116,739)
Proceeds from sale of utility property claim	5,484	-	-
Other capital expenditures	(3,819)	(4,044)	(3,126)
Deposit for utility property acquisition	-	-	(5,000)
Decrease (increase) in restricted cash	(4,269)	541	(9,703)
Changes in other property and investments	(1,980)	2,033	517
Repayments received on notes receivable	429	318	1,062
Proceeds from asset sales	25,706	17,211	2,466
Net cash used in investing activities	(139,715)	(199,282)	(130,523)

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

	2006	2005	2004
Financing Activities:			
Decrease in short-term borrowings	$ (59,494)	$ (5,023)	$ (12,008)
Proceeds from issuance of long-term debt	149,778	149,633	89,761
Redemption and maturity of long-term debt	(199,018)	(111,613)	(66,857)
Proceeds from issuance of long-term debt to affiliated trusts	-	-	61,856
Redemption of long-term debt to affiliated trusts	-	-	(61,856)
Premiums paid for the redemption of long-term debt	(426)	(826)	(6,710)
Long-term debt and short-term borrowing issuance costs	(5,436)	(2,153)	(6,149)
Cash received (paid) in interest rate swap agreement	(3,738)	4,445	125
Redemption of preferred stock	(1,750)	(1,750)	(1,750)
Distribution to minority interests	-	(1,688)	-
Issuance of common stock	88,585	2,066	4,061
Repurchase of subsidiary preferred stock	-	-	(4,285)
Cash dividends paid	(27,927)	(26,443)	(24,912)
Net cash provided by (used in) financing activities	(59,426)	6,648	(28,724)
Net increase (decrease) in cash and cash equivalents	2,325	(62,400)	(39,809)
Cash and cash equivalents at beginning of period	25,917	88,317	128,126
Cash and cash equivalents at end of period	$ 28,242	$ 25,917	$ 88,317
Supplemental Cash Flow Information:			
Cash paid during the period:			
Interest	$ 95,475	$ 85,569	$ 84,220
Income taxes	63,361	26,405	11,321
Non-cash financing and investing activities:			
Common stock issued to settle incentive compensation liability	3,238	-	-
Property and equipment purchased under capital leases	-	-	1,365

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, 2003	48,344,009	$ 615,838	$ (2,424)	$ (8,040)	$ 145,878	$ 751,252
Net income					35,154	35,154
Equity compensation plan transactions		262			(409)	(147)
Issuance of common stock through Dividend Reinvestment Plan	127,502	2,279				2,279
Repayments of note receivable			1,929			1,929
Other comprehensive loss				(12,493)		(12,493)
Cash dividends paid (common stock)					(24,912)	(24,912)
ESOP dividend tax savings					143	143
Balance as of December 31, 2004	48,471,511	$ 618,379	$ (495)	$ (20,533)	$ 155,854	$ 753,205
Net income					45,168	45,168
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)
ESOP dividend tax savings					38	38
Balance as of December 31, 2005	48,593,139	$ 620,598	$ -	$ (23,299)	$ 173,829	$ 771,128
Net income					73,133	73,133
Equity compensation expense		3,092				3,092
Issuance of common stock through equity compensation plans	649,061	11,995			(258)	11,737
Issuance of common stock through Employee Investment Plan (401-K)	14,595	324				324
Issuance of common stock through Dividend Reinvestment Plan	95,031	2,137				2,137
Issuance of common stock	3,162,500	77,474				77,474
Other comprehensive income				9,162		9,162
Cumulative effect of accounting change (adoption of SFAS No. 158)				(3,829)		(3,829)
Cash dividends paid (common stock)					(27,927)	(27,927)
ESOP dividend tax savings					415	415
Balance as of December 31, 2006	52,514,326	$ 715,620	$ -	$ (17,966)	$ 219,192	$ 916,846

The Accompanying Notes are an Integral Part of These Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business
Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Utilities has electric generating facilities in 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. See Note 29 for business segment information.

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

- price and supply of purchased power, fuel and natural gas,
- regulatory recovery of power and natural gas costs and capital investments,
- streamflow and weather conditions,
- effects of changes in legislative and governmental regulations,
- changes in regulatory requirements,
- availability of generation facilities,
- competition,
- technology, and
- availability of funding.

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. All significant intercompany balances have been 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 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 appropriate state regulatory commissions.

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 $21.7 million (net of $51.6 million of unbilled receivables sold) as of December 31, 2006 and $13.1 million (net of $57.1 million of unbilled receivables sold) as of December 31, 2005. See Note 4 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
Avista Energy follows Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, for the majority of its contracts. Avista Energy reports the net margin on derivative commodity instruments held for trading 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, which are not held for trading, are reported on a gross basis in non-utility energy marketing and trading revenues, were $119.9 million in 2006, $144.6 million in 2005 and $116.0 million in 2004.

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 in the other business segment 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 2006, 2005 and 2004.

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 $48.3 million in 2006, $43.1 million in 2005 and $35.0 million in 2004.

Other Income-Net

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

	2006	2005	2004
Interest income	$ 9,366	$ 5,974	$ 4,313
Interest on power and natural gas deferrals	6,497	7,429	7,855
Net gain on the disposition of non-operating assets	76	318	785
Net gain (loss) on investments	(512)	156	434
Premium on repurchase of subsidiary preferred stock	-	-	(892)
Other expense	(9,358)	(6,228)	(6,854)
Other income	2,531	2,381	2,749
Total	$ 8,600	$ 10,030	$ 8,390

Income Taxes

The Company and its eligible subsidiaries file consolidated federal income tax returns. 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 have been resolved with the exception of certain indirect overhead costs (see Note 12).

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 have been established for tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

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 are 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. have granted stock options to employees (exercisable into stock of the respective subsidiary) in more recent periods, which have not been 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 has resulted in changes to stock compensation expense recognition. See Note 2 and Note 24 for further information. The Company adopted SFAS No. 123R using the modified prospective method and, accordingly, financial statement amounts for prior periods presented have not been 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 have been the following pro forma amounts for the years ended December 31 (prior to the adoption of SFAS No. 123R):

	2005	2004
Net income (dollars in thousands):		
As reported	$ 45,168	$ 35,154
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)	(2,033)
Pro forma	$ 44,468	$ 33,121
Basic and diluted earnings per common share:		
Basic as reported	$ 0.93	$ 0.73
Diluted as reported	$ 0.92	$ 0.72
Basic pro forma	$ 0.92	$ 0.68
Diluted pro forma	$ 0.91	$ 0.68

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

	2006	2005
Foreign currency translation adjustment	$ 1,369	$ 1,407
Unfunded benefit obligation for the pension plan	(15,982)	(19,625)
Unrealized loss on interest rate swap agreements	(3,346)	(6,586)
Unrealized loss on securities available for sale	-	(64)
Unrealized gain on derivative commodity instruments	(7)	1,569
Total accumulated other comprehensive loss	$ (17,966)	$ (23,299)

Foreign Currency Translation Adjustment
The assets and liabilities of Avista Energy Canada, Ltd. and its subsidiary, CoPac Management, Inc., are denominated in Canadian dollars and translated to United States dollars at exchange rates in effect on the balance sheet date. Revenues and expenses are translated using an average exchange rate. Translation adjustments resulting from this process are reflected as a component of other comprehensive income (loss) in the Consolidated Statements of Comprehensive Income.

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):

	2006	2005
Bank deposits as collateral for letters of credit (Avista Energy)	$ 24,885	$ 18,200
Bonus retention deposits held in trust (Avista Energy)	76	1,125
Deposits related to forward contracts (Avista Energy)	2,500	2,500
Deposits related to interest rate swap agreements (Avista Corp.)	2,442	3,809
Total	$ 29,903	$ 25,634

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):

	2006	2005	2004
Allowance as of the beginning of the year	$ 44,634	$ 44,193	$ 46,382
Additions expensed during the year	2,895	2,867	3,367
Net deductions	(5,169)	(2,426)	(5,556)
Allowance as of the end of the year	$ 42,360	$ 44,634	$ 44,193

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):

	2006	2005
Materials and supplies	$ 16,050	$ 14,253
Fuel stock	2,122	3,773
Natural gas stored	24,253	36,097
Total	$ 42,425	$ 54,123

Assets Held for Sale
Assets held for sale are recorded at the lower of cost or estimated fair value less selling costs. As of December 31, 2006, assets held for sale included $3.5 million of turbines and related equipment at Avista Utilities. As of December 31, 2005, assets held for sale included $11.9 million of turbines and related equipment. Liabilities held for sale were not significant as of December 31, 2006 and 2005.

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 as a non-cash item in the Consolidated Statements of Income in the line item capitalized interest. 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 2006 and 9.72 percent for 2005 and 2004. 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 2006, 2.93 percent in 2005 and 2.92 percent in 2004.

The average service lives for the following broad categories of utility property are:
- electric thermal production - 28 years,
- hydroelectric production - 77 years,
- electric transmission - 42 years,
- electric distribution - 47 years, and
- natural gas distribution property - 36 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 $197.7 million as of December 31, 2006 and $186.6 million as of December 31, 2005. 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 non-utility properties and investments-net on the Consolidated Balance Sheets and totaled $6.2 million ($5.2 million in the Other business segment and $1.0 million in Energy Marketing and Resource Management) at each of December 31, 2006 and December 31, 2005.

The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2006 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 an independent third-party regulator,
- 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,
- demand side management programs,
- 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. Other regulatory assets consisted of the following as of December 31 (dollars in thousands):

	2006	2005
Regulatory asset for postretirement benefit obligation	$ 2,837	$ 3,309
Demand side management and conservation programs	14,239	12,272
Asset retirement obligations	3,292	2,969
Other	11,384	8,110
Total	$ 31,752	$ 26,660

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 5 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 $63.3 million as of December 31, 2006, of which the majority related to the regulatory asset for pensions and other postretirement benefits of $54.2 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 has 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 average remaining maturity of outstanding debt in accordance with regulatory accounting practices under SFAS No. 71. These costs are recovered through retail rates as a component of interest expense.

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Consolidated Balance Sheets for future review and the opportunity for 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, and
- the level of thermal generation (including changes in fuel prices).

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. 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. Avista Utilities accrues interest on deferred power costs in the Washington jurisdiction at a rate, which is adjusted semi-annually, of 8.25 percent as of December 31, 2006. Total deferred power costs for Washington customers were $70.2 million as of December 31, 2006 and $96.2 million as of December 31, 2005.

In June 2006, the WUTC approved a settlement agreement between the Company, the staff of the WUTC, the Industrial Customers of Northwest Utilities and the office of Public Counsel Section of the Washington Attorney General's Office, representing all parties in the Company's ERM proceeding. The settlement agreement provides for the continuation of the ERM with certain agreed-upon modifications and is effective as of January 1, 2006. The settling parties have agreed to review the ERM after five years.

The settlement agreement modified the ERM such that the Company's annual deadband was reduced from $9.0 million to $4.0 million and the Company will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. Annual power supply cost variances between $4.0 million and $10.0 million are shared equally between the Company and its customers. As such, 50 percent of the annual power supply cost variance in this range is deferred for future surcharge or rebate to the Company's customers and the remaining 50 percent is an expense of, or benefit to, the Company. Once 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 remaining 10 percent of the variance beyond $10.0 million is an expense of, or benefit to, the Company without affecting current or future customer rates. The following table summarizes the historical (prior to January 1, 2006) and modified ERM (effective January 1, 2006):

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
Historical ERM:		
+/- $0 - $9 million	0%	100%
+/- excess over $9 million	90%	10%
Modified ERM:		
+/- $0 - $4 million	0%	100%
+/- between $4 million - $10 million	50%	50%
+/- excess over $10 million	90%	10%

Under the ERM, Avista Utilities makes an annual filing to provide the opportunity for the WUTC and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by WUTC order. In June 2006, the WUTC issued an order, which approved the recovery of the $4.1 million of deferred power costs incurred for 2005.

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 Idaho customers. Avista Utilities accrues interest on deferred power costs in the Idaho jurisdiction at a rate, which is adjusted annually, of 3.0 percent on current year deferrals and 5.0 percent on carryover balances as of December 31, 2006. Total deferred power costs for Idaho customers were $9.4 million as of December 31, 2006 and $8.0 million as of December 31, 2005.

Natural Gas Cost Deferrals and Recovery Mechanisms

Natural gas commodity costs in excess of, or which fall below, the amount recovered in current retail rates are deferred and recovered or refunded as a pass-through to customers in future periods, subject to applicable regulatory review and approval, through adjustments to rates. Currently, purchased gas adjustments provide for the deferral and future recovery or refund of 100 percent of the difference between actual commodity costs and the amount recovered in current retail rates in Washington and Idaho. In Oregon, Avista Utilities receives recovery of 100 percent of the cost of natural gas for which the price is fixed through hedge transactions, and included in retail rates through the annual purchased gas cost adjustment filing. With respect to the unhedged portion of customer loads in Oregon, Avista Utilities defers 90 percent of the difference between actual prices and the amount recovered in current retail rates. Total deferred natural gas costs were $18.3 million as of December 31, 2006 and $43.4 million as of December 31, 2005.

Reclassifications

Certain prior period amounts were reclassified to conform to current statement format. These reclassifications were made for comparative purposes and have not affected previously reported total net income or stockholders' equity.

NOTE 2. NEW ACCOUNTING STANDARDS

The implementation of Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities," as revised in December 2003, resulted in the Company including a partnership as well as several low-income housing project investments held in the Other business segment in its consolidated financial statements beginning in the first quarter of 2004. This resulted in a charge of $0.5 million recorded as a cumulative effect of accounting change for 2004.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment," which supersedes APB No. 25 and SFAS No. 123 and their related implementation guidance. This statement establishes 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 effective January 1, 2006 using the modified prospective method and, accordingly, financial statement amounts for prior periods presented have not been restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. Under the modified prospective approach, SFAS 123R applies to all of the Company's unvested stock-based payment awards beginning January 1, 2006 and all prospective awards. For 2006, the Company recorded $4.0 million (pre-tax) of stock-based compensation expense, which is included in other operating expenses in the Consolidated Statements of Income. As a result of implementing SFAS No. 123R, the Company's income before income taxes increased $1.5 million and net income increased $1.0 million as compared to the amounts that the Company would have recorded for stock-based compensation expense under prior accounting rules. The impact on basic and diluted earnings per share was an increase of $0.02 per share. 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 was 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.

In June 2006, the 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. FIN 48 requires the evaluation of a tax position as a two-step process. First, the Company will be 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 Company will be required to adopt FIN 48 in the first quarter of 2007. The Company does not expect the adoption of FIN 48 to have a material effect on its financial condition and results of operations.

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. The fair value hierarchy gives 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 is evaluating the impact SFAS No. 157 will have on its financial condition and results of operations.

In September 2006, the FASB issued 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)." SFAS No. 158 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 as of December 31, 2006. 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 has recorded 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 has 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 $3.8 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 September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin (SAB) No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements." SAB No. 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB No. 108 requires companies to quantify misstatements using a balance sheet and income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. The adoption of SAB No. 108 in the fourth quarter of 2006 did not have any effect on the Company's results of operations or financial condition.

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 has been elected would be reported in net income. The Company will be required to adopt SFAS No. 159 in 2008. The Company is evaluating the impact SFAS No. 159 will have on its financial condition and results of operations.

NOTE 3. IMPAIRMENT OF ASSETS

In January 2006, the Company completed the sale of a turbine and related equipment owned by Avista Power (Energy Marketing and Resource Management segment), which were classified as assets held for sale as of December 31, 2005. In 2005, the Company recorded impairment charges of $1.0 million for the turbine and related equipment, which is included in other operating expenses in the Consolidated Statements of Income.

The Company originally planned to use four turbines in a non-regulated generation project. Due to changing market conditions during 2001, the Company decided to no longer pursue the development of this project and reached an agreement to sell three of the turbines. During 2002, 2003 and the first three quarters of 2004, the Company explored various options for use of the fourth turbine. At the end of the third quarter of 2004, the Company reached a conclusion to sell the turbine and related equipment, and recorded an impairment charge of $5.1 million, which is included in other operating expenses in the Consolidated Statements of Income.

NOTE 4. 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 20, 2006, 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 21, 2006 to March 20, 2007. 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, 2006 and 2005, $85.0 million in accounts receivables were sold under this revolving agreement.

NOTE 5. UTILITY ENERGY COMMODITY DERIVATIVE ASSETS AND LIABILITIES

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 in Note 6. 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):

	2006	2005
Current utility energy commodity derivative assets	$ 10,828	$ 69,494
Current utility energy commodity derivative liabilities	(73,478)	(3,447)
Net current regulatory liability (asset)	$ (62,650)	$ 66,047
Non-current utility energy commodity derivative assets	$ 25,575	$ 46,731
Non-current utility energy commodity derivative liabilities	(10,175)	(88)
Net non-current regulatory liability	$ 15,400	$ 46,643

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

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,
- interest rates,
- foreign currency, 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 engages in the trading of such instruments. Avista Utilities and Avista Energy use a variety of techniques to manage risks for their energy resources and wholesale energy market activities. The Company has risk management policies and procedures to manage these risks, both qualitative and quantitative, for Avista Utilities and Avista Energy. The Company's Risk Management Committee establishes the Company's risk management policies and 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

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. Prior to April 1, 2005, Avista Energy was responsible for the daily management of natural gas supplies to meet the requirements of Avista Utilities' customers in the states of Washington, Idaho and Oregon. Effective April 1, 2005, the management of natural gas procurement functions was moved from Avista Energy back to Avista Utilities. This was required for Washington customers by WUTC orders issued in February 2004, and Avista Utilities' resulting transition plan was approved by the WUTC in April 2004. The Company also elected to move these functions back to Avista Utilities for Idaho and Oregon natural gas customers. The natural gas procurement process includes entering into financial and physical hedging transactions as a means of managing risks. Avista Utilities always managed natural gas procurement for its California operations, which the Company sold in April 2005 (see Note 28).

Avista Energy

Avista Energy is an electricity and natural gas marketing, trading and resource management business. Avista Energy focuses on 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 is also involved in trading electricity and natural gas, including derivative commodity instruments. Avista Energy purchases natural gas and electricity from producers and energy marketing and trading companies. Its customers include commercial and industrial end-users, electric utilities, natural gas distribution companies, and energy marketing and trading companies.

Avista Energy's marketing and energy risk management services are provided through the use of a variety of derivative commodity contracts to purchase or supply natural gas and electric energy at specified delivery points and at specified future dates. Avista Energy trades natural gas and electric derivative commodity instruments on national exchanges and through other exchanges and brokers, and therefore can experience net open positions in terms of price, volume, and specified delivery point. The open positions expose Avista Energy to the risk that fluctuating market prices may adversely impact its financial condition or results of operations. However, the net open positions are actively managed with policies designed to limit the exposure to market risk and require daily reporting to management of potential financial exposure.

Avista Energy measures the risk in its electric and natural gas portfolio daily utilizing a Value-at-Risk (VAR) model, which monitors risk in comparison to established thresholds. VAR measures the expected portfolio loss under hypothetical adverse price movements over a given time interval within a given confidence level. Avista Energy also measures its open positions in terms of volumes at each delivery location for each forward time period. The permissible extent of open positions is included in the risk management policy and is measured with stress tests and VAR modeling.

Derivative commodity instruments sold and purchased by Avista Energy include: forward contracts, which involve physical delivery of an energy commodity; futures contracts, which involve the buying or selling of natural gas or electricity at a fixed price; over-the-counter swap agreements, which require Avista Energy to receive or make payments based on the difference between a specified price and the actual price of the underlying commodity; and options, which mitigate price risk by providing for the right, but not the requirement, to buy or sell energy-related commodities at a fixed price. Foreign currency risks are primarily related to Canadian exchange rates and are managed using standard instruments available in the foreign currency markets.

Avista Energy's derivative commodity instruments accounted for under SFAS No. 133 are subject to mark-to-market accounting, under which changes in the market value of outstanding electric, natural gas and related derivative commodity instruments are recognized as unrealized gains or losses in the Consolidated Statements of Income in the period of change. Market prices are utilized in determining the value of electric, natural gas and related derivative commodity instruments, which are reported as assets and liabilities on the Consolidated Balance Sheets. These market prices are used through 36 months. For longer-term positions and certain short-term positions for which market prices are not available, a model to estimate forward price curves is utilized. Avista Energy reports the net margin on derivative commodity instruments held for trading as non-utility energy marketing and trading 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 non-utility energy marketing and trading revenues. Costs from contracts, which are not derivatives under SFAS No. 133 and derivative instruments not held for trading, are reported on a gross basis in non-utility resource costs. Contracts in a receivable position, as well as the options held, are reported as assets. Similarly, contracts in a payable position, as well as options written, are reported as liabilities. Net cash flows are recognized in the period of settlement.

Avista Energy has implemented hedge accounting in accordance with SFAS No. 133. Specific natural gas and electric trading derivative contracts have been designated as hedging instruments in cash flow hedging relationships. The hedge strategies represent cash flow hedges of the variable price risk associated with expected purchases of natural gas and sales of electricity. These designated hedging instruments represent hedges of variable price exposures generated from certain contracts, which do not qualify as derivatives under

SFAS No. 133. For all derivatives designated as cash flow hedges, Avista Energy documents the:

- relationship between the hedging instrument and the hedged item (forecasted purchases and sales of power and natural gas), and
- risk management objective and strategy for using the hedging instrument.

Avista Energy assesses whether a change in the value of the designated derivative is highly effective in achieving offsetting cash flows attributable to the hedged item, both at the inception of the hedge and on an ongoing basis. Any changes in the fair value of the designated derivative that are effective are recorded in accumulated other comprehensive income or loss, while changes in fair value that are not effective are recognized currently in earnings as operating revenues. Amounts recorded in accumulated other comprehensive income or loss are recognized in earnings during the period that the hedged items are recognized in earnings.

The following table presents activity related to Avista Energy's hedge accounting during the years ended December 31 (dollars in thousands):

	2006	2005	2004
Gain (loss) related to hedge ineffectiveness recorded in operating revenues	$ (2,650)	$ 8,445	$ 1,020
Gain reclassified from accumulated other comprehensive income (loss) and recognized in earnings (pre-tax)	840	2,566	735

Of the $2.6 million in pre-tax hedge ineffectiveness recorded in operating revenues for 2006, $2.3 million relates to designated hedges that matured during 2006. The balance of $0.3 million relates to designated hedging relationships that were outstanding as of December 31, 2006.

The following table presents the net gain (loss), net of tax, related to Avista Energy's cash flow hedges as of December 31 (dollars in thousands):

	2006	2005
Accumulated other comprehensive income related to natural gas derivatives	$ 272	$ 11,583
Accumulated other comprehensive loss related to electric derivatives	(279)	(10,014)
Total accumulated other comprehensive income (loss)	$ (7)	$ 1,569

Avista Energy expects to recognize the full amount of other comprehensive loss in earnings during the next 12 months. The actual amounts that will be recognized in earnings during the next 12 months will vary from the expected amounts as a result of changes in market prices. The maximum term of the designated hedging instruments was 12 months.

Contract Amounts and Terms

Under Avista Energy's derivative instruments, Avista Energy either (i) as "fixed price payor," is obligated to pay a fixed price or a fixed amount and is entitled to receive the commodity or a fixed amount, (ii) as "fixed price receiver," is entitled to receive a fixed price or a fixed amount and is obligated to deliver the commodity or pay a fixed amount, (iii) as "index price payor," is obligated to pay an indexed price or an indexed amount and is entitled to receive the commodity or a variable amount or (iv) as "index price receiver," is entitled to receive an indexed price or amount and is obligated to deliver the commodity or pay a variable amount. The contract or notional amounts and terms of Avista Energy's derivative commodity instruments outstanding as of December 31, 2006 are set forth below (in thousands of MWhs and mmBTUs):

	Fixed Price Payor	Fixed Price Receiver	Maximum Terms in Years	Index Price Payor	Index Price Receiver	Maximum Terms in Years
Energy commodities (volumes)						
Electric	26,162	28,479	11	6,794	6,165	3
Natural gas	127,113	114,243	5	699,858	723,715	5

The weighted average term of Avista Energy's electric derivative commodity instruments as of December 31, 2006 was approximately 8 months. The weighted average term of Avista Energy's natural gas derivative commodity instruments as of December 31, 2006 was approximately 4 months.

Estimated Fair Value

The estimated fair value of Avista Energy's derivative commodity instruments outstanding as of December 31, 2006, and the average estimated fair value of those instruments held during the year ended December 31, 2006, are set forth below (dollars in thousands):

	Estimated Fair Value as of December 31, 2006				Average Estimated Fair Value for the year ended December 31, 2006			
	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities
Electric	$ 168,297	$ 295,499	$ 143,285	$ 286,467	$ 207,877	$ 361,301	$ 193,674	$ 351,272
Natural gas	175,429	17,801	170,214	23,523	292,510	36,172	281,519	38,944
Total	$ 343,726	$ 313,300	$ 313,499	$ 309,990	$ 500,387	$ 397,473	$ 475,193	$ 390,216

The change in the estimated fair value position of Avista Energy's energy commodity portfolio, net of reserves for credit and market risk for 2006 was an unrealized gain of $1.5 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 2005 was an unrealized loss of $38.1 million. In 2004, the unrealized loss was $0.7 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 nonperformance by market participants of their contractual obligations and commitments affect the supply of, or demand for, the commodity. Avista Utilities and Avista Energy manage the market risks inherent in their activities according to risk policies established by the Company's Risk Management Committee.

Credit Risk

Credit risk relates to the risk of loss that Avista Utilities and/or Avista Energy would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy or make financial settlements. Avista Utilities and Avista Energy often extend credit to counterparties and customers and are 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 have been 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, Avista Utilities or Avista Energy may be required to replace existing contracts with contracts at then-current market prices or to honor the underlying commitment.

Avista Utilities and Avista Energy seek to mitigate credit risk by:

- applying specific eligibility criteria to existing and prospective counterparties, and
- actively monitoring current credit exposures.

These 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. Avista Utilities and Avista Energy also use 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,
- natural gas distribution companies, 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 Avista Utilities and Avista Energy 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,
- cash deposits, and
- parent company performance guarantees (only pertains to Avista Capital guarantees of Avista Energy).

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. Avista Utilities and Avista Energy actively monitor the exposure to possible collateral calls and take 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:

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

Terrorism threats, both domestic and foreign, 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 $41.5 million as of December 31, 2006 and $13.7 million as of December 31, 2005. These funds are held by Avista Utilities and Avista Energy 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 totaled $79.5 million as of December 31, 2006 and $59.4 million as of December 31, 2005.

As is common industry practice, Avista Utilities and Avista Energy maintain 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 and Avista Energy. Negotiating for collateral in the form of cash, letters of credit, or parent company performance guarantees is a 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 $329.0 million and accumulated depreciation was $192.5 million as of December 31, 2006.

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):

	2006	2005
Avista Utilities:		
Electric production	$ 991,794	$ 988,539
Electric transmission	383,824	369,567
Electric distribution	832,094	790,630
Construction work-in-progress (CWIP) and other	162,071	119,690
Electric total	2,369,783	2,268,426
Natural gas underground storage	18,672	18,550
Natural gas distribution	502,237	471,574
CWIP and other	52,646	56,465
Natural gas total	573,555	546,589
Common plant (including CWIP)	98,344	96,319
Total Avista Utilities	3,041,682	2,911,334
Energy Marketing and Resource Management [1]	18,157	17,360
Advantage IQ [1]	17,355	14,736
Other [1]	34,711	36,624
Total	$ 3,111,905	$ 2,980,054

(1) Included in non-utility 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," which requires the recording of 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. As asset retirement costs are recovered through rates charged to customers, the Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded under SFAS 143. The regulatory assets do not earn a return.

The Company adopted FIN 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143," as of December 31, 2005, which resulted in the recording of additional asset retirement obligations under SFAS No. 143. Specifically, the Company recorded liabilities for future asset retirement obligations to:

- restore ponds at Colstrip,
- 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):

	2006	2005
Asset retirement obligation at beginning of year	$ 4,529	$ 1,191
New liability recognized	-	3,243
Liability settled	(51)	(28)
Accretion expense	332	123
Asset retirement obligation at end of year	$ 4,810	$ 4,529

The pro forma asset retirement obligation liability balance as if FIN 47 had been adopted on January 1, 2005 (rather than December 31, 2005) is as follows (dollars in thousands):

Pro forma asset retirement obligation as of January 1, 2005	$	4,246

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 made $15 million in cash contributions to the pension plan in each of 2006, 2005 and 2004. The Company expects to contribute $15 million to the pension plan in 2007.

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 Company expects that benefit payments under the pension plan and the SERP will total $14.0 million in 2007, $14.2 million in 2008, $14.5 million in 2009, $15.8 million in 2010 and $16.4 million in 2011. For the ensuing five years (2012 through 2017), the Company expects that benefit payments under the pension plan and the SERP will total $102.6 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, 2006 and 2005.

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 will also increase future years' pension costs.

As of December 31, 2006 and 2005, the pension and other postretirement benefit plans had assets with a market-related value that was less than the present value of the benefit obligation under the plans. In 2006, the Company adopted SFAS No. 158, which resulted in the recording of adjustments to the Consolidated Balance Sheet as disclosed in Note 2.

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 $2.9 million in 2007, $2.8 million in 2008, $2.7 million in 2009, $2.5 million in 2010 and $2.5 million 2011. For the ensuing five years (2012 through 2016), the Company expects that benefit payments under the postretirement benefit plan will total $10.9 million. The Company expects to contribute $2.9 million to the postretirement benefit plan in 2007, 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 postretirement benefits.

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, 2006 and 2005 and the components of net periodic benefit costs for the years ended December 31, 2006, 2005 and 2004 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2006	2005	2006	2005
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 301,746	$ 285,738	$ 28,963	$ 31,868
Service cost	9,963	9,480	544	566
Interest cost	17,158	16,228	1,755	1,652
Plan amendment	-	-	-	-
Actuarial loss (gain)	2,524	5,352	2,386	(1,800)
Benefits paid	(15,521)	(14,932)	(3,557)	(3,293)
Expenses paid	(179)	(120)	(30)	(30)
Benefit obligation as of end of year	$ 315,691	$ 301,746	$ 30,061	$ 28,963
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 199,163	$ 186,579	$ 18,378	$ 16,862
Actual return on plan assets	25,737	11,763	2,530	1,236
Employer contributions	15,000	15,000	-	1,183
Benefits paid	(14,642)	(14,059)	-	(873)
Expenses paid	(179)	(120)	(30)	(30)
Fair value of plan assets as of end of year	$ 225,079	$ 199,163	$ 20,878	$ 18,378
Funded status	$ (90,612)	$ (102,583)	$ (9,183)	$ (10,585)
Unrecognized net actuarial loss	69,679	79,667	2,318	973
Unrecognized prior service cost	3,751	4,405	-	-
Unrecognized net transition obligation/(asset)	-	-	3,031	3,536
Accrued benefit cost	(17,182)	(18,511)	(3,834)	(6,076)
Additional liability	(73,430)	(34,595)	(5,349)	-
Accrued benefit liability	$ (90,612)	$ (53,106)	$ (9,183)	$ (6,076)
Accumulated pension benefit obligation	$ 264,647	$ 252,269	-	-
Accumulated postretirement benefit obligation:				
For retirees			$ 18,548	$ 14,662
For fully eligible employees			$ 5,401	$ 5,980
For other participants			$ 6,112	$ 8,321
Weighted-average asset allocations as of December 31:				
Equity securities	53%	63%	64%	62%
Debt securities	28%	27%	33%	36%
Real estate	5%	5%	-	-
Other	14%	5%	3%	2%
Target asset allocations as of December 31:				
Equity securities	39-61%	54-68%	52-72%	52-72%
Debt securities	27-33%	22-28%	28-48%	28-48%
Real estate	3-7%	3-7%	-	-
Other	10-22%	5-13%	-	-
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	6.15%	5.75%	6.15%	5.75%
Discount rate for annual expense	5.75%	5.75%	5.75%	5.75%
Expected long-term return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.84%	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			2011	2010
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			2010	2009

	2006	2005	2004	2006	2005	2004
Components of net periodic benefit cost:						
Service cost	$ 9,963	$ 9,480	$ 8,914	$ 544	$ 566	$ 480
Interest cost	17,158	16,228	16,406	1,755	1,652	2,019
Expected return on plan assets	(16,997)	(15,917)	(13,436)	(1,562)	(1,368)	(1,106)
Transition (asset)/obligation recognition	-	(499)	(1,086)	505	505	505
Amortization of prior service cost	653	654	654	-	-	-
Net loss recognition	3,772	3,442	3,447	90	-	245
Net periodic benefit cost	$ 14,549	$ 13,388	$ 14,899	$ 1,332	$ 1,355	$ 2,143

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, 2006 by $1.4 million and the service and interest cost by $0.1 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, 2006 by $1.2 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 $4.7 million in 2006, $4.4 million in 2005 and $4.1 million in 2004.

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, 2006 and 2005, there were deferred compensation assets of $12.6 million and $11.3 million included in other property and investments-net and corresponding deferred compensation liabilities of $12.6 million and $11.3 million included in other non-current liabilities and deferred credits on the Consolidated Balance Sheets.

NOTE 12. ACCOUNTING FOR INCOME TAXES

A reconciliation of federal income taxes derived from statutory federal tax rates (35 percent in 2006, 2005 and 2004) 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):

	2006	2005	2004
Federal income taxes at statutory rates	$ 40,328	$ 24,860	$ 20,022
Increase (decrease) in tax resulting from:			
Tax effect of regulatory treatment of utility plant differences	4,342	2,870	2,273
State income tax expense	1,853	1,139	821
Preferred dividends	670	713	759
Settlement of prior year tax returns and adjustment of tax reserves	(1,437)	42	(2,830)
Manufacturing deduction	(735)	(385)	-
Kettle Falls tax credit	(3,201)	(2,891)	-
Other-net	270	(487)	547
Total income tax expense	$ 42,090	$ 25,861	$ 21,592
Income tax expense consisted of the following:			
Taxes currently provided	$ 61,198	$ 16,996	$ 2,424
Deferred income taxes	(19,108)	8,865	19,168
Total income tax expense	$ 42,090	$ 25,861	$ 21,592

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):

	2006	2005
Deferred income tax assets:		
Allowance for doubtful accounts	$ 14,911	$ 16,604
Reserves not currently deductible	9,581	14,213
Foreign tax credit	4,088	3,357
Contributions in aid of construction	11,778	7,691
Deferred compensation	5,051	5,164
Unfunded benefit obligation	30,401	9,100
Utility energy commodity derivatives	34,669	40,679
Interest rate swaps	1,801	3,485
Other	10,087	10,812
Total deferred income tax assets	122,367	111,105
Deferred income tax liabilities:		
Differences between book and tax basis of utility plant	417,255	417,841
Power and natural gas deferrals	34,454	51,332
Regulatory asset for pensions and other postretirement benefits	18,967	-
Unrealized energy commodity gains	12,154	12,252
Power exchange contract	34,101	37,024
Utility energy commodity derivatives	34,669	40,679
Demand side management programs	4,477	3,518
Loss on reacquired debt	8,869	9,325
Foreign subsidiary income	4,088	3,357
Other	3,407	10,192
Total deferred income tax liabilities	572,441	585,520
Net deferred income tax liability	$ 450,074	$ 474,415

Net current deferred income tax assets were $10.9 million as of December 31, 2006 and $14.5 million as of December 31, 2005. Net non-current deferred tax liabilities were $461.0 million as of December 31, 2006 and $488.9 million as of December 31, 2005.

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.

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

Due to the revenue rulings and related regulations, the IRS has disallowed the accelerated tax deductions during their recent exam. 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. has appealed the proposed IRS adjustment on April 19, 2006. The Company's appeal has been received, but has not yet been scheduled for review by the IRS Appeals Division. The Company repaid a portion of the accelerated tax deduction 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 had net regulatory assets of $105.9 million as of December 31, 2006 and $114.1 million as of December 31, 2005 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 and various agreements for the purchase, sale 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 $682.5 million in 2006, $652.2 million in 2005 and $482.2 million in 2004. 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):

	2007	2008	2009	2010	2011	Thereafter	Total
Power resources	$ 109,915	$ 103,526	$ 102,898	$ 103,003	$ 74,785	$ 463,737	$ 957,864
Natural gas resources	215,668	96,054	83,625	57,901	56,563	719,503	1,229,314
Total	$ 325,583	$ 199,580	$ 186,523	$ 160,904	$ 131,348	$ 1,183,240	$ 2,187,178

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):

	2007	2008	2009	2010	2011	Thereafter	Total
Contractual obligations	$ 15,438	$ 15,463	$ 15,611	$ 15,637	$ 15,666	$ 196,863	$ 274,678

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 $13.1 million in 2006, $9.0 million in 2005 and $7.3 million in 2004.

Information as of December 31, 2006 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	$ 2,031	$ 984	$ 2,179	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,218	809	4,724	2018
Grant County PUD:						
Priest Rapids Project	2.9%	55,000	6,898	561	7,876	2055
Wanapum Project	8.2%	75,000	2,932	1,870	12,938	2055
Totals		197,000	$ 13,079	$ 4,224	$ 27,717	

(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 2006. 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):

	2007	2008	2009	2010	2011	Thereafter	Total
Minimum payments	$ 3,519	$ 3,594	$ 3,620	$ 2,738	$ 2,683	$ 27,962	$ 44,116

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):

	2007	2008	2009	2010	2011	Thereafter	Total
Energy contracts	$ 397,552	$ 257,493	$ 213,317	$ 196,331	$ 36,438	$ 369,569	$ 1,470,700

Avista Energy also has sales commitments related to these contractual obligations in future periods.

NOTE 14. SHORT-TERM BORROWINGS

On April 6, 2006, the Company amended its committed line of credit agreement with various banks. The committed line of credit was originally entered into on December 17, 2004. Amendments to the committed line of credit include a reduction in the total amount of the facility to $320.0 million from $350.0 million and an extension of the expiration date to April 5, 2011 from December 16, 2009. The Company chose to reduce the facility based on forecasted liquidity needs. Under the amended credit agreement, the Company can request the issuance of up to $320.0 million in letters of credit, an increase from $150.0 million prior to the amendment. Total letters of credit outstanding were $77.1 million as of December 31, 2006 and $44.1 million as of December 31, 2005. The amended 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 amended 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, 2006, the Company was in compliance with this covenant with a ratio of 2.56 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. Under the amendment, this ratio limitation will be increased to 75 percent during the period between the completion of the proposed change in the Company's corporate organization (see Note 26) and December 31, 2007. As of December 31, 2006, the Company was in compliance with this covenant with a ratio of 53.7 percent. If the proposed change in organization becomes effective, the committed line of credit agreement 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):

	2006	2005	2004
Balance outstanding at end of period	$ 4,000	$ 63,000	$ 68,000
Maximum balance outstanding during the period	77,000	167,000	170,000
Average balance outstanding during the period	16,740	61,181	54,858
Average interest rate during the period	6.07%	4.45%	3.14%
Average interest rate at end of period	8.25%	5.48%	3.52%

Avista Energy and its subsidiary, Avista Energy Canada, as co-borrowers, have a committed credit agreement with a group of banks in the aggregate amount of $145.0 million with an expiration date of July 12, 2007. This committed credit facility provides for the issuance of letters of credit to secure contractual obligations to counterparties and for cash advances. This facility is secured by the assets of Avista Energy and Avista Energy Canada and guaranteed by Avista Capital and by CoPac Management, Inc., a wholly owned subsidiary of Avista Energy Canada. The maximum amount of credit extended by the banks for the issuance of letters of credit is the subscribed amount of the facility less the amount of outstanding cash advances, if any. The maximum amount available for cash advances under the credit agreement is $50.0 million. No cash advances were outstanding as of December 31, 2006 and 2005. The total aggregate amount of letters of credit outstanding was $52.5 million as of December 31, 2006 and $125.3 million as of December 31, 2005. The cash deposits of Avista Energy at the respective banks collateralized $24.9 million and $18.2 million of these letters of credit as of December 31, 2006 and 2005, which is reflected as restricted cash on the Consolidated Balance Sheets.

The Avista Energy credit agreement contains covenants and default provisions, including covenants to maintain "minimum net working capital" and "minimum net worth," as well as a covenant limiting the amount of indebtedness that the co-borrowers may incur. The credit agreement also contains covenants and other restrictions related to the co-borrowers' trading limits and positions, including VAR limits, restrictions with respect to changes in risk management policies or volumetric limits, and limits on exposure related to hourly and daily trading of electricity. These covenants, certain counterparty agreements and market liquidity conditions result in Avista Energy maintaining certain levels of cash and therefore effectively limit the amount of cash dividends that are available for distribution to Avista Capital and ultimately to Avista Corp. Avista Energy was in compliance with the covenants of its credit agreement as of December 31, 2006.

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	2006	2005
2006	Secured Medium-Term Notes	7.89-7.90%	$ -	$ 30,000
2007	First Mortgage Bonds [1]	7.75%	-	150,000
2007	Secured Medium-Term Notes	5.99%	13,850	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	6.37%	25,000	25,000
2032	Pollution Control Bonds	5.00%	66,700	66,700
2034	Pollution Control Bonds	5.13%	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds [1]	5.70%	150,000	-
	Total secured long-term debt		$ 680,550	$ 710,550
2006	Unsecured Medium-Term Notes	8.14%	$ -	$ 8,000
2007	Unsecured Medium-Term Notes	7.90-7.94%	12,000	12,000
2008	Unsecured Senior Notes	9.75%	272,860	279,735
2023	Pollution Control Bonds	6.00%	4,100	4,100
	Total unsecured long-term debt		288,960	303,835
	Other long-term debt and capital leases		7,364	11,506
	Interest rate swaps		1,037	5,236
	Unamortized debt discount		(1,452)	(1,613)
	Total		976,459	1,029,514
	Current portion of long-term debt		(26,605)	(39,524)
	Total long-term debt		$ 949,854	$ 989,990

(1) During December 2006, the Company issued $150.0 million of 5.70 percent First Mortgage Bonds due in 2037. The proceeds from the issuance were used to legally defease $150.0 million of First Mortgage Bonds that were scheduled to mature on January 1, 2007.

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

Year	2007	2008	2009	2010	2011	Thereafter	Total
Debt maturities	$ 25,850	$ 317,860	$ -	$ 35,000	$ -	$ 704,203	$ 1,082,913

Substantially all utility properties owned by the Company are subject to the lien of the Company's various mortgage indentures. The Mortgage and Deed of Trust securing the Company's First Mortgage Bonds (including Secured Medium-Term Notes) contains limitations on the amount of First Mortgage Bonds, which may be issued based on, among other things, a 70 percent debt-to-collateral ratio, and/or retired First Mortgage Bonds, and a 2 to 1 net earnings to First Mortgage Bond interest ratio. As of December 31, 2006, the Company could issue $429.5 million of additional First Mortgage Bonds under the Mortgage and Deed of Trust. 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 2006 ranged from 5.285 percent to 6.275 percent. As of December 31, 2006, the annual distribution rate was 6.244 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 in 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

In 2004, Avista Corp. entered into three forward-starting interest rate swap agreements, totaling $200.0 million, 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 to fund debt that matures in 2007 and 2008. 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 (totaling $75.0 million) and paid $3.7 million. These settlements have been 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 remaining agreements (totaling $125.0 million), 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.

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, 2006, Avista Corp. had a long-term derivative liability of $5.1 million and a net unrealized loss of $3.3 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 $5.4 million in 2006, $7.2 million in 2005 and $9.9 million in 2004.

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2006 were as follows (dollars in thousands):

Year ending December 31:	2007	2008	2009	2010	2011	Thereafter	Total
Minimum payments required	$ 4,413	$ 4,309	$ 3,929	$ 1,548	$ 201	$ 2,915	$ 17,315

NOTE 19. GUARANTEES

The $145.0 million committed credit agreement of Avista Energy and its subsidiary, Avista Energy Canada, as co-borrowers, is guaranteed by Avista Capital and by CoPac Management, Inc., and secured by the assets of Avista Energy and Avista Energy Canada. This credit agreement expires on July 12, 2007. This agreement also provides for the issuance of letters of credit to secure contractual obligations to counterparties. No cash advances were outstanding as of December 31, 2006 and 2005. The aggregate amount of letters of credit outstanding was $52.5 million as of December 31, 2006 and $125.3 million as of December 31, 2005.

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.

In the course of the energy trading business, Avista Capital provides guarantees to other parties with whom Avista Energy may be doing business. At any point in time, Avista Capital is only liable for the outstanding portion of the guarantee, which was $27.5 million as of December 31, 2006 and $37.7 million as of December 31, 2005. The face value of all performance guarantees issued by Avista Capital for energy trading contracts at Avista Energy was $362.4 million as of December 31, 2006 and $419.3 million as of December 31, 2005. Most guarantees do not have set expiration dates; however, either party may terminate the guarantee at any time with minimal written notice.

Avista Power, through its equity investment in Rathdrum Power, LLC (RP LLC), was a 49 percent owner of the Lancaster Project, 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. Commencing with commercial operations, all of the output from the Lancaster Project 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.

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

In September 2006, 2005 and 2004, the Company made mandatory redemptions of 17,500 shares of preferred stock for $1.75 million. The 262,500 remaining shares must be redeemed on September 15, 2007 for $26.25 million. Upon involuntary liquidation, all preferred stock will be entitled to $100 per share plus accrued dividends.

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 (excluding $3.4 million of debt that is considered common equity by the affiliated trusts) and preferred stock subject to mandatory redemption as of December 31, 2006 and 2005 (dollars in thousands):

	2006		2005	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt	$ 969,510	$ 976,548	$ 1,014,385	$ 1,063,018
Long-term debt to affiliated trusts	110,000	106,744	110,000	104,595
Preferred stock	26,250	26,622	28,000	28,636

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 2006, 2005 and 2004 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, 2006, the Company is meeting 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 issued 3,162,500 shares of common stock through an underwriter and received net proceeds of $77.7 million. Also, 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 26, 2007, 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):

	2006	2005	2004
Numerator:			
Net income before cumulative effect of accounting change	$ 73,133	$ 45,168	$ 35,614
Cumulative effect of accounting change	-	-	(460)
Net income	$ 73,133	$ 45,168	$ 35,154
Denominator:			
Weighted-average number of common shares outstanding-basic	49,162	48,523	48,400
Effect of dilutive securities:			
Contingent stock awards	371	198	209
Stock options	364	258	277
Weighted-average number of common shares outstanding-diluted	49,897	48,979	48,886
Earnings per common share, basic:			
Earnings before cumulative effect of accounting change	$ 1.49	$ 0.93	$ 0.74
Loss from cumulative effect of accounting change	-	-	(0.01)
Total earnings per common share, basic	$ 1.49	$ 0.93	$ 0.73
Earnings per common share, diluted:			
Earnings before cumulative effect of accounting change	$ 1.47	$ 0.92	$ 0.73
Loss from cumulative effect of accounting change	-	-	(0.01)
Total earnings per common share, diluted	$ 1.47	$ 0.92	$ 0.72

Total stock options outstanding that were not included in the calculation of diluted earnings per common share were 26,200 for 2006, 695,500 for 2005 and 730,100 for 2004. 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, 2006, 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, 2006, 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 have not been restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. For 2006, the Company recorded $4.0 million (pre-tax) of stock-based compensation expense, which is included in other operating expenses in the Consolidated Statements of Income.

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 and 2004. Avista Corp. has not granted any stock options since 2003. The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

	2006	2005	2004
Number of shares under stock options:			
Options outstanding at beginning of year	2,095,211	2,332,198	2,481,886
Options granted	-	-	-
Options exercised	(504,452)	(192,377)	(99,138)
Options canceled	(49,714)	(44,610)	(50,550)
Options outstanding at end of year	1,541,045	2,095,211	2,332,198
Options exercisable at end of year	1,541,045	1,968,629	1,896,648
Weighted average exercise price:			
Options granted	$ -	$ -	$ -
Options exercised	$ 16.12	$ 13.50	$ 13.79
Options canceled	$ 20.77	$ 20.42	$ 18.46
Options outstanding at end of year	$ 15.41	$ 15.68	$ 15.58
Options exercisable at end of year	$ 15.41	$ 16.03	$ 16.62

Information for options outstanding and exercisable as of December 31, 2006 was as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17-$11.68	388,695	$ 10.28	5.8
$11.69-$14.61	398,375	11.82	4.9
$14.62-$17.53	274,900	17.07	3.2
$17.54-$20.45	155,625	18.75	2.1
$20.46-$26.29	297,250	22.56	3.8
$26.30-$28.47	26,200	27.39	2.6
Total	1,541,045	$ 15.41	4.3

The aggregate intrinsic value of options outstanding and exercisable was $15.3 million as of December 31, 2006. The aggregate intrinsic value represents the difference between Avista Corp.'s closing price on the last trading day of the period and the exercise price, multiplied by the number of in-the-money options. This is the value that would have been received by the option holders had all options holders exercised their options on December 31, 2006. The intrinsic value of options exercised during 2006 was $3.5 million and total cash received from the exercise of stock options was $9.9 million. At December 31, 2005, the Company had approximately 125,000 unvested stock options outstanding with a weighted average grant date fair value of $3.28 per share. As of December 31, 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 average of the high and low market of the Company's common stock on the grant date. As of December 31, 2006, the restricted shares had unrecognized compensation expense of $0.4 million and an intrinsic value of $0.9 million. The intrinsic value represents the total market value of restricted shares as of December 31, 2006. The following table summarizes restricted stock activity:

Unvested Shares at December 31, 2005	-
Shares granted	36,260
Shares cancelled	(80)
Shares vested	-
Unvested Shares at December 31, 2006	36,180
Weighted average fair value at grant date	$ 21.32

12,073 of restricted shares vested on January 3, 2007 that were granted in 2006.

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 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 benchmarks the Company's Total Shareholder Return (TSR) performance over a three-year period 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 measured (at the grant date) the estimated fair value of performance shares granted in 2006, 2005 and 2004 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 Monte Carlo valuation model. 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:

	2006	2005	2004
Risk-free interest rate	4.6%	3.4%	2.4%
Expected life, in years	3	3	3
Expected volatility	21.9%	34.1%	38.8%
Dividend yield	2.9%	3.0%	3.4%

The fair value of performance shares granted was estimated to be the following in the year ended December 31:

	2006	2005	2004
Weighted average grant date fair value (per share)	$ 18.08	$ 16.70	$ 17.16

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

During 2006, the Company granted 138,340 performance shares of which 138,042 were outstanding and unvested as of December 31, 2006, to certain officers and other key employees. In 2005, the Company granted 163,600 performance shares to certain officers and other key employees, of which 162,364 awards were outstanding and unvested as of December 31, 2006.

The Company granted 156,800 performance shares in 2004. Based on the Company's TSR as compared to the benchmark during the 3-year performance cycle, the Company issued 189,382 shares of common stock in January 2007 related to the performance shares granted in 2004. The Company issued 183,497 shares of common stock in the first quarter of 2006 related to the performance shares granted in 2003.

Unrecognized compensation expense for performance share awards was $2.4 million as of December 31, 2006, of which $1.6 million and $0.8 million is expected to be expensed during 2007 and 2008. The aggregate intrinsic value of all performance share awards outstanding as of December 31, 2006 was $11.5 million, which represents the total market value of all performance shares outstanding. This is the value that would have been received by the share recipients had all performance shares been vested and paid out at 100 percent on December 31, 2006.

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, 2006, the Company had recognized compensation expense and a liability of $0.7 million related to the dividend component of performance share grants.

Avista Capital Companies

Certain subsidiaries of Avista Capital have employee stock incentive plans under which certain employees and directors of the subsidiaries are granted options to purchase subsidiary shares at prices no less than the fair market value on the date of grant. Options outstanding under these plans generally vest over periods of between three and five years from the date granted and terminate ten years from the date granted. Employee stock incentive plans related to the Avista Capital subsidiaries are not significant to the consolidated financial statements. Unrecognized compensation expense for stock based awards at the Avista Capital subsidiaries was $1.1 million as of December 31, 2006, which is expected to be expensed during 2007 through 2010.

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.

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. 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 November 10, 2005, an amended class action complaint was filed in the United States District Court for the Eastern District of Washington against Avista Corp., Thomas M. Matthews, the former Chairman of the Board, President and Chief Executive Officer of Avista Corp., Gary G. Ely, the current Chairman of the Board and Chief Executive Officer of Avista Corp., and Jon E. Eliassen, the former Senior Vice President and Chief Financial Officer of Avista Corp. Several class action complaints were originally filed in September through November 2002 in the same court against the same parties. In February 2003, the court issued an order, which consolidated the complaints and in August 2003, the plaintiffs filed a consolidated amended class action complaint. On June 13, 2005, the Company filed a motion for reconsideration of its earlier motion to dismiss this complaint, based, in part, on a recent United States Supreme Court decision with respect to the pleading requirements surrounding a sufficient showing of loss causation. On October 19, 2005, the Court granted the Company's motion to dismiss this complaint. The order to dismiss was issued without prejudice, which allowed the plaintiffs to amend their complaint. The amended complaint filed on November 10, 2005 alleges damages due to the decrease in the total market value of the Company's common stock during the class period, alleged to be approximately $2.6 billion. These alleged losses stemmed from alleged violations of federal securities laws through alleged misstatements and omissions of material facts with respect to the Company's energy trading practices in western power markets. The plaintiffs assert that alleged misstatements and omissions regarding these matters were made in the Company's filings with the Securities and Exchange Commission and other information made publicly available by the Company, including press releases. The class action complaint asserts 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. On January 6, 2006, the Company filed a motion to dismiss the November 10, 2005 complaint, asserting deficiencies in the amended complaint, including that the plaintiffs failed to adequately allege loss causation. On June 2, 2006, the U.S. District Court entered an order denying the Company's motion to dismiss the complaint. The U.S. District Court's order denying the Company's motion to dismiss is not a decision on the merits of the lawsuit. On September 16, 2006, the plaintiffs filed a motion for class certification. On February 13, 2007, the plaintiffs' motion for class certification was heard before the court. Also, pending before the court is defendants' motion for summary judgment seeking to dismiss plaintiffs' claims on the ground that they are barred by the applicable statute of limitations. The matter is expected to proceed in the normal course of litigation and a trial date is currently scheduled for November 13, 2007. Because the resolution of this lawsuit 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 this lawsuit will have a material adverse effect on its financial condition, results of operations or cash flows.

California Refund Proceeding
In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) during the period from October 2, 2000 to June 20, 2001 (Refund Period) in the California spot power market. 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 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 mitigated market clearing price methodology is applied to its transactions. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In February 2007, the CalISO filed a status report at the FERC stating that it will take approximately 10 weeks to complete the financial adjustment phase related to transactions in its markets during the Refund Period. The report also stated that the CalISO intends to process Avista Energy's cost claim. The CalISO states that its efforts related to cost filing offsets will require five business weeks to complete. In January 2007, Avista Energy joined in a settlement filed at the FERC by participants

in markets operated by the Automated Power Exchange (APX). The settlement, if approved by the FERC, provides for a comprehensive resolution of all disputes and other matters with respect to the APX related claims.

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, 2006, 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. Market participants with bids above $250 per MW during the period described above have been required to demonstrate why their bidding behavior and practices did not violate applicable market rules. If violations were found to exist, the FERC would require the refund of any unjust profits and could also enforce other non-monetary penalties, such as the revocation of market-based rate authority. Avista Energy was subject to this review. 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 United States Court of Appeals for 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 have been 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 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. The Ninth Circuit has extended until April 29, 2007, the time for filing petitions for rehearing. 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 Court of Appeals.

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 in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. During the hearing, 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. Seven petitions for review, including one filed by Puget Sound Energy, Inc. (Puget), are now pending before the United States Court of Appeals for the Ninth Circuit. Opening briefs were filed in January 2005. Petitioners other than Puget challenged the merits of the FERC's decision not to order refunds. Puget's brief is directed to the procedural flaws in the underlying docket. Puget argues that because its complaint was withdrawn as a matter of law in July 2001, the FERC erred in relying on it to serve as the basis to initiate the preliminary investigation into whether refunds for individually negotiated bilateral transactions in the Pacific Northwest were appropriate. In February 2005, intervening parties, including Avista Energy and Avista Utilities, filed in support of Puget and also filed in opposition to the other six petitioners. Briefing was completed in May 2005 and oral arguments were heard on January 8, 2007. Because the resolution of the Pacific Northwest 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 Pacific Northwest refund proceeding will have a material adverse effect on its financial condition, results of operations 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 United States Court of Appeals for the Ninth Circuit. In September 2004, the United States Court of Appeals for 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. Based on its current schedule, the Ninth Circuit will issue the mandate on this decision on April 29, 2007, which will return the case to the FERC for further proceedings. On December 28, 2006 certain parties filed a petition for a writ of certiorari at the Supreme Court, which is currently pending. 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 is similar to the Port of Seattle complaint (which has been dismissed by the United States District Court and the United States Court of Appeals for the Ninth Circuit as disclosed in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006) and seeks 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 alleges 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 alleges 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 United States Court of Appeals for the Ninth Circuit. The appeal of Wah Chang is still pending before the Ninth Circuit and oral argument is set for April 10, 2007. Because the resolution of this lawsuit 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 this lawsuit will have a material adverse effect on its financial condition, results of operations or cash flows.

City of Tacoma Complaint

In June 2004, the City of Tacoma, Department of Public Utilities, Light Division, a Washington municipal corporation (Tacoma Power), filed a complaint in the United States District Court for the Western District of Washington against over fifty companies, including Avista Corp., Avista Energy and Avista Power. According to the complaint, Tacoma Power distributes electricity to customers in Tacoma; and Pierce County, Washington, generates electricity at several facilities in western Washington and purchases power under supply contracts and in the Northwest spot market. Tacoma Power's complaint is similar to the Port of Seattle complaint (which has been dismissed by the United States District Court and the United States Court of Appeals for the Ninth Circuit as disclosed in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006) and seeks compensatory and treble damages from alleged violations of the Sherman Act. Tacoma Power alleges that the defendants, acting in concert, engaged in a pattern of activities that had the purpose and effect of creating the impressions that the demand for power was higher, the supply of power was lower, or both, than was in fact the case. This allegedly resulted in an artificial increase of the prices paid for power sold in California and elsewhere in the western United States during the period from May 2000 through the end of 2001. Due to the alleged unlawful conduct of the defendants, Tacoma Power allegedly paid an amount estimated to be $175.0 million in excess of what it would have paid in the absence of such alleged conduct. 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 this complaint for similar reasons to those expressed by the Court in the Wah Chang complaint described above. In March 2005, Tacoma Power filed an appeal with the United States Court of Appeals for the Ninth Circuit. The appeal of Tacoma Power is still pending before the Ninth Circuit and oral argument is set for April 10, 2007. Because the resolution of this lawsuit 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 this lawsuit will have a material adverse effect on its 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 all 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 requests lease payments dating back to the construction of the respective dams and also requests damages for trespassing and unjust enrichment. In February 2004, the Company filed its motion to dismiss this lawsuit; PacifiCorp and PPL Montana, the other named defendants, also filed a motion to dismiss, or joined therein. 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. In July 2004, the defendants (including Avista Corp.) filed a motion to dismiss the Montana AG's complaint. In September 2004, the motion to dismiss the Montana AG's complaint was denied, rejecting the defendants' argument, among other things, that the FERC has exclusive jurisdiction over this matter. In September 2005, the U.S. District Court issued an order vacating its prior decision based on lack of jurisdiction.

In November 2004, the defendants (including Avista Corp.) filed a petition for declaratory relief in Montana State Court requesting the resolution of the controversy that the plaintiffs raised in federal court, as discussed above, and the Montana AG filed an answer, counterclaim and motion for summary judgment. In June 2005, Avista Corp. moved for leave to amend its complaint to, inter alia, add two causes of action relating to breach of contract and negligent misrepresentation arising out of its Clark Fork Settlement Agreement that was entered into in 1999 with the State of Montana relating to the relicensing of Avista Corp.'s Noxon Rapids Hydroelectric Generating Project. On April 14, 2006, the Montana State Court granted the Montana AG's motion for summary judgment and denied Avista Corp.'s motion to amend its complaint to add its breach of contract and negligent misrepresentation claims. However, the Montana State Court granted Avista Corp.'s motion to amend its complaint to contend that the Clark Fork River is not navigable. The Company contends that if the Clark Fork River was not navigable at the time of statehood in 1889, the State of Montana never acquired ownership of the riverbeds under the equal footing doctrine. The Court determined that the Montana AG's claims for compensation were not preempted by the Federal Power Act because it was not, on its face, in conflict with Montana law, nor were they preempted by a federal navigational right for purposes of interstate commerce. The Court also rejected defenses based on estoppel, waiver, and the statute of limitations. The Court did not relieve the Montana AG, however, of its obligation to prove that the State of Montana actually owns the riverbeds or that the land is part of a school trust under the Montana Constitution. In addition, the question of whether there is federal preemption under the Federal Power Act, not on its face, but as actually applied in these circumstances, and the question of compensation, still remain open issues in the case. On May 16, 2006, the State of Montana filed a motion for summary judgment on the question of liability. On October 6, 2006, the Company filed several motions, which addressed, among other things, the question of navigability of the Clark Fork River arguing that since the Clark Fork River was not navigable at the time of statehood, the State of Montana never acquired ownership of the riverbeds under the equal footing doctrine. Oral arguments on the Company's motions were heard in December 2006. The Company expects this matter to proceed in the normal course of litigation and a trial date is currently scheduled for October 2007. Because the resolution of this lawsuit remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, the Company intends to seek recovery, through the rate making process, of any amounts paid.

Colstrip Generating Project Complaint

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. The Company intends to continue to work with the other owners of Colstrip in defense of this complaint. Because the resolution of this lawsuit 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 this lawsuit will have a material adverse effect on its financial condition, results of operations or cash flows.

Environmental Protection Agency Administrative Compliance Order

In December 2003, PPL Montana, LLC, as operator of Colstrip, received an Administrative Compliance Order (ACO) from the Environmental Protection Agency (EPA) pursuant to the Clean Air Act (CAA). In January 2006, the EPA issued a draft settlement agreement related to the ACO. The ACO alleges that Colstrip Units 3 & 4 have been in violation of the CAA permit at Colstrip since the units came on-line in the 1980s. The permit required the Colstrip project operator to submit for review and approval by the EPA an analysis and proposal for reducing emissions of nitrogen oxides to address visibility concerns if, and when, EPA promulgates Best Available Retrofit Technology requirements for nitrogen oxide emissions. The EPA is asserting that regulations it promulgated in 1980 triggered this requirement. Avista Utilities and the other owners of Colstrip believe that the ACO is unfounded. The owners of Colstrip are discussing the proposed settlement agreement with the EPA, the Department of Environmental Quality (Montana DEQ) and the Northern Cheyenne Tribe. The draft settlement agreement would resolve the potential liability related to this issue and would result in the installation of additional nitrogen oxide emissions control equipment at Colstrip. Because the resolution of this issue remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, the Company intends to seek recovery, through the rate making process, of any amounts paid (including capitalized costs).

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 an order to WECO to pay additional royalties concerning coal delivered to Colstrip Units 3 & 4 via the conveyor belt (4.46 miles long). The owners of Colstrip Units 3 & 4 take delivery of the coal at the western end (beginning) of the conveyor belt. The order asserts that additional royalties are owed 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, 2001. WECO's appeal to the MMS was substantially denied in March 2005; WECO has now appealed the order to the Board of Land Appeals of the U.S. Department of the Interior. 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 has 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. Under the agreement with the DOE and Kaiser, the Company is performing the selected remedial action under the Cleanup Action Plan. Kaiser, operating under Chapter 11 bankruptcy protection, paid the Company approximately 50 percent of the estimated total costs, which was approved by the Kaiser bankruptcy judge has been used by the Company to fund the costs of the remediation. The Company accrued its share of the total estimated costs, which was not material to the Company's financial condition or results of operations. Under the direction of the Company, work under the Cleanup Action Plan was substantially completed by January 2007. Final work should be completed in the second quarter of 2007. Because of uncertainties with respect to, among other things, unforeseen site conditions, 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.

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 fuel spill occurred when Co-op made a delivery of diesel to a tank that was already nearly full causing excess fuel to overflow into a containment area. It is estimated that approximately 26,000 gallons of fuel escaped the containment area and leaked into the soil below it. An investigation, supervised by the DOE, determined the fuel was, for the most part, uniformly present in the soil to a depth of 30-35 feet. Groundwater below the site is at a depth of 170 feet. The Company immediately commenced remediation efforts, including the removal of contaminated soil and the related fuel storage facilities. Options to dispose of the contaminated soil are currently being evaluated. The Company accrued the estimated cleanup costs during 2005, which was not material to the Company's consolidated financial condition or results of operations. During the fourth quarter of 2005, the Company filed a complaint against Co-op and an engineering firm to recover a substantial portion of the cleanup costs. Through mediation the Company recovered a substantial portion of the cleanup costs from Co-op and the engineering firm in the fourth quarter of 2006. Because of uncertainties related to the disposal of the contaminated soil, 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, 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. Harbor Oil's primary business was the collection and blending of used oil for sale as fuel to ships at sea. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Thirteen other companies received a similar notice, including current and former owners of the site, the Bonneville

Power Administration, Portland General Electric Company, Northwestern Energy and Unocal Oil. Several meetings have been held with the EPA and certain of the Potentially Responsible Parties (PRPs) to ask questions of the EPA regarding the Harbor Oil site, as well as drafting an administrative compliance order related to conducting a remedial investigation and feasibility study for the site. 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 United States Court of Appeals for 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. The license for the Spokane River Project expires on August 1, 2007; 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 has 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 dealing with 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 calling for 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. This assumes all conditions, both mandatory and recommended, as well as the Company's proposed conditions, would be included in a final license issued by the FERC, which the Company believes to be unlikely. 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, totals between $175 million and $225 million over a 50-year period. These cost estimates are based on the preliminary conditions and recommendations and will be updated based on the outcome of the FERC proceedings.

The Company requested a trial-type hearing on facts in front of a (ALJ) 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 factual findings support, in several key areas, its analysis of the facts at hand. The ALJ's factual findings also support the DOI's analysis in certain areas as well.

The Bureau of Indian Affairs, which is part of the DOI and is charged with protecting project-related resources on the Coeur d'Alene Indian Reservation and has authority to set conditions for the Company's license, is now expected to use the ALJ's findings to formulate final mandatory conditions for the operation of Post Falls.

The broader relicensing process continues under the jurisdiction of the FERC. The FERC issued a draft environmental impact statement (DEIS) in December 2006 that is open for public review and comment until March 6, 2007. This document includes the FERC's initial analysis of the applications, along with analysis of proposed recommended and mandatory terms and conditions. While the FERC's analysis leads the Company to believe the ultimate cost of relicensing may be less than its earlier projections as disclosed above, the Company is unable to base specific new cost estimates on it.

The relicensing process also triggers review under the Endangered Species Act. The Company prepared a draft Biological Assessment in 2005. In the DEIS, the FERC analyzed potential project impacts on listed and threatened endangered species, and has determined that the proposed action and continued operation of the Post Falls and Spokane River projects, is not likely to adversely effect any threatened or endangered species. The FERC has issued a Biological Assessment and formally requested concurrence from the United States Department of Fish and Wildlife Service (USFWS). The USFWS may either concur or request formal consultation. Should they request formal consultation, additional evaluation will be required.

Following the comment period, the FERC will request final terms and conditions from agencies, the Coeur d'Alene Tribe and others. After that time, the FERC would issue a final environmental impact statement and, ultimately, license orders on Post Falls and the Spokane River Project. In addition, the Company must receive Clean Water Act Certifications from the states of Idaho and Washington for the Projects. Applications for such certification were filed last July with each state; the FERC is precluded from issuing a license order until such certification has been issued, or waived, by the states. The Company cannot predict the schedule for these final phases of relicensing.

If the FERC is unable to issue new license orders prior to the August 1, 2007 expiration of the current license, an annual license will be issued, in effect extending the current license and its conditions. The Company has no reason to believe that Spokane River Project operations would be interrupted in any manner relative to the timing of the FERC's actions.

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 U.S. Fish and Wildlife Service 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 its tunnel solution. The Company has completed its preliminary design development efforts (which include additional computer model studies, some site investigation, and preliminary engineering design) and the cost estimates have been updated. An analysis of the predicted total dissolved gas (TDG) performance indicates that it would not meet the standards anticipated in the GSCP. The costs of modifying the first tunnel are now estimated to be $58 million (using 2006 dollars with inflation projected at 5 percent) with the majority of these costs to be incurred in 2008 through 2011, an increase from prior estimates of $38 million and an extension of the schedule of at least one year. The calculated updated cost estimates to modify the second tunnel are $39 million, an increase from prior estimates of $26 million. The second tunnel would be modified only after evaluation of the performance of the first tunnel and such modifications would commence no later than 10 years following the completion of the first tunnel. The increases in costs are mainly due to inflation and large increases in materials costs, such as concrete and steel. As a result of the predicted TDG performance, the new cost estimates and extension of the schedule, the Company is meeting with stakeholders to explore possible 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, including the mitigation payments.

The U.S Fish and Wildlife Service 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 U.S. Fish and Wildlife Service, 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 (including cap and trade emission reduction programs), as well as other greenhouse gas and mercury emissions. In particular, the EPA has 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 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 10-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. Avista Corp. owns a 15 percent interest in Colstrip Units 3 & 4, located in Montana. 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, are in the process of computing estimates for the amount of these costs and the impact the restrictions will have on the operation of the facilities. The Company will continue to seek recovery, through the rate making process, of the costs to comply with various air quality requirements.

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, 2006, 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. Two local agreements in Oregon, which cover approximately 50 employees, expire in April 2010. Another local agreement in Oregon is up for negotiations in 2007.

NOTE 26: POTENTIAL HOLDING COMPANY FORMATION

At the 2006 Annual Meeting of Shareholders on May 11, 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 now held by Avista Corp. (Avista Capital Dividend), 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. Since the company's 9.75 percent Senior Notes due June 1, 2008 contain a restriction that would prohibit the Avista Capital Dividend (but not the holding company structure), the dividend would not be distributed until the Senior Notes are retired.

Avista Corp. received approval from the FERC in April 2006 (conditioned on approval by the state regulatory agencies) and from the IPUC in June 2006. Avista Corp. also has filed for approval from the utility regulators in Washington, Oregon and Montana. 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 after mid-2007.

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. has 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. 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.

In January 2007, Avista Corp. entered into a similar stipulation with the WUTC staff. As of February 26, 2007, the stipulation is subject to approval by the WUTC. The stipulation would require 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 between 2007 and 2012. Total payments under these contracts were $12.5 million in 2006, $12.8 million in 2005 and $12.8 million in 2004. The majority of these costs are included in other operating expenses in the Consolidated Statements of Income. Minimum contractual obligations under the Company's information services contracts are $12.2 million in 2007, $12.6 million in 2008, $13.0 million in 2009, $13.4 million in 2010, $13.8 million in 2011 and $14.2 million in 2012. The most significant 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. Total revenues for 2004 from the South Lake Tahoe region were approximately $20.3 million (or 6 percent of total natural gas revenues) and approximately 22.1 million therms (or 4 percent of total therms) were delivered to South Lake Tahoe customers.

NOTE 29. INFORMATION BY BUSINESS SEGMENTS

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	Intersegment Eliminations[1]	Total
For the year ended December 31, 2006:						
Operating revenues	$ 1,267,938	$ 177,551	$ 39,636	$ 21,186	$ -	$ 1,506,311
Resource costs	751,646	144,137	-	-	-	895,783
Gross margin	516,292	33,414	-	-	-	549,706
Other operating expenses	187,161	19,198	27,069	20,279	-	253,707
Depreciation and amortization	81,904	977	2,088	2,114	-	87,083
Income (loss) from operations	177,345	13,239	10,479	(1,207)	-	199,856
Interest expense [2]	95,521	199	609	1,769	(1,931)	96,167
Income taxes	33,231	6,595	3,616	(1,352)	-	42,090
Net income (loss)	57,986	11,567	6,255	(2,675)	-	73,133
Capital expenditures	161,266	1,042	2,627	150	-	165,085
For the year ended December 31, 2005:						
Operating revenues	$ 1,161,317	$ 167,439	$ 31,748	$ 18,532	$ (19,429)	$ 1,359,607
Resource costs	669,596	165,423	-	-	(19,429)	815,590
Gross margin	491,721	2,016	-	-	-	493,737
Other operating expenses	181,478	18,795	22,738	18,120	-	241,131
Depreciation and amortization	80,914	1,488	2,037	2,472	-	86,911
Income (loss) from operations	165,378	(18,267)	6,973	(2,060)	-	152,024
Interest expense [2]	91,847	395	912	1,694	(2,134)	92,714
Income taxes	29,967	(4,981)	2,147	(1,272)	-	25,861
Net income (loss)	52,479	(8,621)	3,922	(2,612)	-	45,168
Capital expenditures	215,341	1,573	1,106	1,365	-	219,385
For the year ended December 31, 2004:						
Operating revenues	$ 972,574	$ 275,646	$ 23,444	$ 17,127	$ (137,211)	$ 1,151,580
Resource costs	519,002	236,804	-	-	(137,211)	618,595
Gross margin	453,572	38,842	-	-	-	492,414
Other operating expenses	180,418	25,797	19,800	21,781	-	247,796
Depreciation and amortization	72,787	1,364	1,902	2,372	-	78,425
Income (loss) from operations	134,073	11,681	1,742	(7,026)	-	140,470
Interest expense [2]	92,068	528	874	1,008	(1,431)	93,047
Income taxes	18,383	5,421	334	(2,546)	-	21,592
Net income (loss) before cumulative effect of accounting change	32,467	9,733	577	(7,163)	-	35,614
Net income (loss)	32,467	9,733	577	(7,623)	-	35,154
Capital expenditures	116,739	1,455	840	831	-	119,865
Total Assets:						
Total assets as of December 31, 2006	$ 2,895,883	$ 1,017,203	$ 100,431	$ 42,991	$ -	$ 4,056,508
Total assets as of December 31, 2005	2,838,154	2,012,354	46,094	51,892	-	4,948,494

(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.

The business segment presentation reflects the basis currently 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 consists 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. Advantage IQ (formerly Avista Advantage) is a provider of facility information and cost management services for multi-site customers throughout North America. The Other business segment includes other investments and operations of various subsidiaries as well as certain other operations of Avista Capital.

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. A summary of quarterly operations (in thousands, except per share amounts) for 2006 and 2005 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2006				
Operating revenues	$ 499,202	$ 287,394	$ 293,001	$ 426,714
Operating expenses	428,264	244,816	258,910	374,465
Income from operations	70,938	42,578	34,091	52,249
Net income	$ 31,572	$ 13,459	$ 10,073	$ 18,029
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	$ 0.36
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
2005				
Operating revenues	$ 362,664	$ 272,832	$ 265,679	$ 458,432
Operating expenses	324,481	226,822	261,752	398,621
Gain on sale of utility properties	-	3,209	884	-
Income from operations	38,183	49,219	4,811	59,811
Net income (loss)	$ 10,189	$ 18,604	$ (9,037)	$ 25,412
Outstanding common stock:				
Weighted average	48,478	48,508	48,538	48,568
End of period	48,501	48,532	48,561	48,593
Total earnings (loss) per common share, diluted	$ 0.21	$ 0.38	$ (0.19)	$ 0.52
Dividends paid per common share	$ 0.135	$ 0.135	$ 0.135	$ 0.14
Trading price range per common share:				
High	$ 18.37	$ 18.66	$ 20.20	$ 19.55
Low	$ 16.62	$ 16.31	$ 17.90	$ 16.76

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 principals 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 principals 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 has determined that the Company's internal control over financial reporting as of December 31, 2006 is effective.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report on the following page, which expresses unqualified opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting as of December 31, 2006.

Gary G. Ely
Chairman 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 management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Avista Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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, 2006 of the Company and our report dated February 26, 2007, expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's adoption of new accounting standards.

Deloitte & Touche LLP

Seattle, Washington
February 26, 2007

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, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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 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). Additionally, during 2004, as described in Note 2, the Company was required to consolidate a partnership as well as several low-income housing project investments related to the adoption of Financial Accounting Standards Board Interpretation No. 46(R), Consolidation of Variable Interest Entities (revised December 2003) – an interpretation of ARB No. 51.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, 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, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Seattle, Washington
February 26, 2007

Avista Corporation
For the Years Ended December 31
Dollars in thousands, except per share data and ratios

	2006	2005	2004	2003	2002	1996
FINANCIAL RESULTS						
Operating revenues	$ 1,506,311	$ 1,359,607	$ 1,151,580	$ 1,123,385	$ 1,062,916	$ 944,957
Operating expenses	1,306,455	1,211,676	1,011,110	951,682	905,774	758,036
Gain on sale of utility properties	-	4,093	-	-	-	-
Income from operations	199,856	152,024	140,470	171,703	157,142	186,921
Interest expense	96,167	92,714	93,047	92,985	104,866	63,255
Income taxes	42,090	25,861	21,592	35,340	34,849	49,509
Income from continuing operations	73,133	45,168	35,614	50,643	42,174	83,453
Loss from discontinued operations	-	-	-	(4,949)	(6,719)	-
Net income before cumulative effect of accounting change	73,133	45,168	35,614	45,694	35,455	83,453
Cumulative effect of accounting change	-	-	(460)	(1,190)	(4,148)	-
Net income	73,133	45,168	35,154	44,504	31,307	83,453
Preferred stock dividend requirements [1]	-	-	-	(1,125)	(2,402)	(7,978)
Income available for common stock	$ 73,133	$ 45,168	$ 35,154	$ 43,379	$ 28,905	$ 75,475
Earnings per common share, diluted:						
Earnings from continuing operations	$ 1.47	$ 0.92	$ 0.73	$ 1.02	$ 0.83	$ 1.37
Loss from discontinued operations	-	-	-	(0.10)	(0.14)	-
Earnings before cumulative effect of accounting change	1.47	0.92	0.73	0.92	0.69	1.37
Cumulative effect of accounting change	-	-	(0.01)	(0.03)	(0.09)	-
Total earnings per common share, diluted	$ 1.47	$ 0.92	$ 0.72	$ 0.89	$ 0.60	$ 1.37
Total earnings per common share, basic	$ 1.49	$ 0.93	$ 0.73	$ 0.90	$ 0.60	$ 1.37
COMMON STOCK STATISTICS						
Dividends paid per common share	$ 0.570	$ 0.545	$ 0.515	$ 0.49	$ 0.48	$ 1.24
Book value per common share	$ 17.46	$ 15.87	$ 15.54	$ 15.54	$ 14.84	$ 12.70
Shares of common stock:						
Outstanding at year-end	52,514	48,593	48,472	48,344	48,044	55,960
Average - basic	49,162	48,523	48,400	48,232	47,823	55,960
Average - diluted	49,897	48,979	48,886	48,630	47,874	55,960
Return on average common equity:						
Total company	8.7%	5.9%	4.7%	5.9%	4.0%	10.6%
Utility only	9.6%	10.2%	6.6%	7.4%	8.2%	9.4%
Non-utility only	6.2%	-3.0%	1.0%	3.2%	-1.7%	15.6%
Common stock price:						
High	$ 27.52	$ 20.20	$ 19.17	$ 18.70	$ 16.60	$ 19.88
Low	$ 17.61	$ 16.31	$ 15.51	$ 9.80	$ 8.75	$ 17.25
Year-end close	$ 25.31	$ 17.71	$ 17.67	$ 18.12	$ 11.56	$ 18.63

Avista Corporation
For the Years Ended December 31
Dollars in thousands, except per share data and ratios

	2006	2005	2004	2003	2002	1996
DEBT AND PREFERRED STOCK STATISTICS						
Pretax interest coverage:						
Including AFUDC/AFUCE	2.11(x)	1.84(x)	1.60(x)	1.78(x)	1.59(x)	3.12(x)
Excluding AFUDC/AFUCE	2.06(x)	1.80(x)	1.56(x)	1.76(x)	1.57(x)	3.08(x)
Embedded cost of long-term debt	7.79%	8.09%	8.27%	8.44%	8.88%	7.79%
Embedded cost of preferred stock	7.39%	7.39%	7.39%	7.35%	7.42%	7.00%
Credit Ratings (Standard & Poor's/Moody's)						
Senior secured debt	BBB-/Baa3	BBB-/Baa3	BBB-/Baa3	BBB-/Baa3	BBB-/Baa3	A/A3
Senior unsecured debt	BB+/Ba1	BB+/Ba1	BB+/Ba1	BB+/Ba1	BB+/Ba1	A-/Baa1
Preferred stock	BB-/Ba3	BB-/Ba3	BB-/Ba3	BB-/Ba3	BB-/Ba3	A-/Baa1
FINANCIAL CONDITION						
Total assets	$ 4,056,508	$ 4,948,494	$ 3,711,621	$ 3,640,075	$ 3,799,543	$ 2,177,298
Total net utility property	2,215,037	2,126,417	1,956,063	1,914,001	1,749,114	1,397,876
Utility property capital expenditures (excluding AFUDC)	161,266	215,341	116,739	102,271	64,207	88,821
Long-term debt (not including current portion)	949,854	989,990	901,556	925,012	902,635	764,526
Long-term debt to affiliated trusts [2]	113,403	113,403	113,403	113,403	-	-
Preferred trust securities [2]	-	-	-	-	100,000	-
Preferred stock subject to mandatory redemption [1]	26,250	28,000	29,750	31,500	33,250	115,000
Common equity	$ 916,846	$ 771,128	$ 753,205	$ 751,252	$ 712,791	$ 710,736

(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.

(2) Preferred trust securities was reclassified to Long-term debt to affiliated trusts in 2003 with the adoption of FASB Interpretation No. 46 and the deconsolidation of the capital trusts that have issued the preferred trust securities.

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

	2006	2005	2004	2003	2002	1996
AVISTA UTILITIES						
Electric Operations						
Electric operating revenues (millions of dollars):						
Residential	$ 234.7	$ 211.9	$ 209.5	$ 204.8	$ 196.1	$ 160.3
Commercial	221.2	203.5	201.8	201.3	194.7	144.7
Industrial	92.9	91.6	90.3	78.3	68.1	62.1
Public street and highway lighting	5.3	4.9	4.8	4.8	4.7	3.4
Total retail revenues	554.1	511.9	506.4	489.2	463.6	370.5
Wholesale revenues	126.2	151.4	62.4	73.4	64.1	230.6
Revenues from sales of fuel	48.2	41.8	64.0	71.5	40.9	-
Other revenues	18.9	18.0	19.3	16.8	15.5	26.6
Total electric operating revenues	$ 747.4	$ 723.1	$ 652.1	$ 650.9	$ 584.1	$ 627.7
Electric energy sales (millions of kWhs):						
Residential	3,578	3,420	3,343	3,298	3,203	3,220
Commercial	3,110	2,994	2,919	2,919	2,837	2,674
Industrial	2,062	2,091	2,076	1,785	1,519	1,839
Public street and highway lighting	25	25	25	25	25	24
Total retail energy sales	8,775	8,530	8,363	8,027	7,584	7,757
Wholesale energy sales	2,117	2,508	1,472	2,075	2,215	11,175
Total electric energy sales	10,892	11,038	9,835	10,102	9,799	18,932
Retail electric customers (average per year):						
Residential	300,940	294,036	288,422	283,497	279,735	257,726
Commercial	37,912	37,282	36,728	36,279	35,910	33,043
Industrial	1,388	1,408	1,416	1,414	1,420	1,133
Public street and highway lighting	425	421	418	422	413	363
Total retail electric customers	340,665	333,147	326,984	321,612	317,478	292,265
Retail electric customers (at year-end):						
Residential	305,293	298,961	292,150	287,141	282,269	261,514
Commercial	38,362	37,587	37,040	36,551	36,106	33,588
Industrial	1,378	1,393	1,416	1,426	1,409	981
Public street and highway lighting	417	428	408	436	426	366
Total retail electric customers	345,450	338,369	331,014	325,554	320,210	296,449
Revenue per residential kWh (cents)	6.56	6.20	6.27	6.21	6.12	4.98
Use per residential customer (kWh)	11,888	11,630	11,591	11,633	11,450	12,493
Revenue per commercial kWh (cents)	7.11	6.80	6.91	6.90	6.86	5.41
Use per commercial customer (kWh)	82,028	80,314	79,465	80,472	78,995	80,933
Electric energy resources (millions of kWhs):						
Hydro generation (from Company facilities)	4,128	3,611	3,789	3,540	4,010	5,045
Thermal generation (from Company facilities)	3,434	3,666	2,408	2,398	1,714	2,764
Purchased power - long-term hydro contracts	787	864	794	775	836	1,170
Purchased power - wholesale	3,101	3,519	3,422	3,909	3,828	10,641
Power exchanges	35	10	38	36	13	102
Total power resources	11,485	11,670	10,451	10,658	10,401	19,722
Energy losses and company use	(593)	(632)	(616)	(556)	(602)	(790)
Total electric energy resources	10,892	11,038	9,835	10,102	9,799	18,932

SELECTED FINANCIAL DATA

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

	2006	2005	2004	2003	2002	1996
Electric Operations (continued)						
Total resources available at peak (MW):						
Company owned:						
Hydro	980	980	965	955	955	972
Thermal	837	836	532	695	426	698
Purchased power:						
Long-term hydro contracts	143	70	167	174	159	138
Other	658	670	888	733	673	1,532
Total resources available at peak (winter)	2,618	2,556	2,552	2,557	2,213	3,340
Net system peak demand (winter)	1,656	1,660	1,766	1,509	1,346	1,711
Wholesale obligations	431	282	454	417	297	1,469
Total requirements (winter)	2,087	1,942	2,220	1,926	1,643	3,180
Reserve margin	18%	24%	13%	25%	26%	5%
Annual load factor	59%	56%	62%	65%	62%	57%
Average cost of production (cents per kWh)	3.33	3.08	2.78	2.76	2.30	2.22
Natural Gas Operations						
Natural gas operating revenues (millions of dollars):						
Residential	$ 257.8	$ 229.7	$ 194.5	$ 166.9	$ 184.0	$ 85.9
Commercial	146.6	126.6	104.7	90.5	105.0	51.0
Industrial	11.7	11.9	9.4	7.5	7.1	5.0
Total retail revenues	416.1	368.2	308.6	264.9	296.1	141.9
Wholesale revenues	93.2	58.1	0.2	0.3	0.7	9.9
Transportation revenues	6.5	7.6	8.1	8.5	9.6	12.2
Other revenues	4.8	4.3	3.6	3.6	3.4	7.3
Total natural gas operating revenues	$ 520.6	$ 438.2	$ 320.5	$ 277.3	$ 309.8	$ 171.3
Natural gas therms delivered (millions of therms):						
Residential	192.8	199.4	201.7	198.5	199.7	183.9
Commercial	121.0	123.0	122.8	122.1	126.2	132.7
Industrial	11.0	13.5	13.3	12.7	11.3	17.0
Total retail	324.8	335.9	337.8	333.3	337.2	333.6
Wholesale	154.9	72.9	0.3	0.7	2.3	67.7
Transportation and other	150.2	153.5	157.5	156.5	177.0	260.1
Total natural gas therms delivered	629.9	562.3	495.6	490.5	516.5	661.4
Retail natural gas customers (average per year):						
Residential	267,345	265,294	268,571	261,063	254,700	203,245
Commercial	31,746	31,652	31,886	31,312	30,823	25,747
Industrial	295	307	311	310	315	328
Total retail natural gas customers	299,386	297,253	300,768	292,685	285,838	229,320
Retail natural gas customers (at year-end):						
Residential	272,109	265,502	272,871	266,252	258,738	210,464
Commercial	32,173	31,476	31,675	31,732	31,141	26,755
Industrial	304	299	304	312	309	328
Total retail natural gas customers	304,586	297,277	304,850	298,296	290,188	237,547

SELECTED FINANCIAL DATA

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

		2006		2005		2004		2003		2002		1996
Natural Gas Operations (continued)												
Revenue per residential therm (in dollars)		1.34		1.15		0.96		0.84		0.92		0.47
Use per residential customer (therms)		721		752		751		760		784		905
Revenue per commercial therm (in dollars)		1.21		1.03		0.85		0.74		0.83		0.38
Use per commercial customer (therms)		3,811		3,885		3,853		3,900		4,095		5,156
Heating degree days (at Spokane, Washington):												
Actual		6,332		6,538		6,314		6,351		6,818		7,477
30 year average		6,820		6,820		6,820		6,820		6,842		6,842
Actual as a percent of average		93%		96%		93%		93%		100%		109%
ENERGY MARKETING AND RESOURCE MANAGEMENT												
Operating revenues (millions of dollars)	$	177.5	$	167.4	$	275.6	$	307.1	$	222.6	$	-
Resource costs (millions of dollars)		144.1		165.4		236.8		246.9		168.4		-
Gross margin (millions of dollars)	$	33.4	$	2.0	$	38.8	$	60.2	$	54.2	$	-
Gross Physical Realized Sales Volume												
Electricity (thousands of MWhs)		25,943		28,377		32,629		41,579		40,426		-
Natural gas (thousands of dekatherms)		154,808		182,874		219,719		228,397		225,983		-
Total assets (millions of dollars)	$	1,017.2	$	2,012.4	$	1,002.8	$	1,013.2	$	1,349.6	$	0.3
ADVANTAGE IQ												
Revenues (millions of dollars)	$	39.6	$	31.7	$	23.4	$	19.8	$	16.9	$	-
Total assets (millions of dollars)	$	100.4	$	46.1	$	47.3	$	5.6	$	31.7	$	-
OTHER												
Revenues (millions of dollars)	$	21.2	$	18.5	$	17.1	$	13.6	$	14.6	$	145.2
Total assets (millions of dollars)	$	43.0	$	51.9	$	53.3	$	48.3	$	42.9	$	254.0

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
The Bank of New York 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 The Bank of New York's Web site at www.stockbny.com.

Inquiries should be directed to:
The Bank of New York
Shareholder Relations Department
P.O. Box 11258
Church Street Station
New York, New York 10286-1258
800.642.7365
shareowners@bankofny.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, Washington 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 10, 2007, 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 8, 2006, the Chief Executive Officer of Avista 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 has included as exhibits to its annual report on Form 10-K for the year 2006 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 2006. Our 2006 annual report is provided to our 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 individuals of the great Inland Northwest for their help with this year's annual report: Anderson Mraz Design; J. Craig Sweat Photography; Clark County PUD (photo – page 8); and Lawton Printing.

INCREASING SHAREHOLDER VALUE IS A PRIMARY GOAL FOR AVISTA.
You can help us meet this goal by agreeing to receive future annual reports and proxy statements electronically. This service saves on the costs of printing and mailing; provides timely delivery of information; and helps protect our environment by decreasing the need for paper, printing and mailing materials. To elect electronic access, please go to www.avistacorp.com.

AVISTA
Corp.

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