AVISTA CORP
Form 10-K
February 27, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2007

OR

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

Commission file number 1-3701

AVISTA CORPORATION

(Exact name of Registrant as specified in its charter)

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

Registrant s telephone number, including area code: 509-489-0500

Web site: http://www.avistacorp.com

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

Title of Class	**Name of Each Exchange on Which Registered**
Common Stock, no par value, together with Preferred Share Purchase Rights appurtenant thereto	New York Stock Exchange

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

Title of Class

Preferred Stock, Cumulative, Without Par Value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.

Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days:

Yes x No ¨

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

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

Large accelerated filer x Accelerated filer ¨

Non-accelerated filer ¨ Smaller reporting company ¨

(Do not check if a smaller reporting company)

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act):

Yes ¨ No x

The aggregate market value of the Registrant s outstanding Common Stock, no par value (the only class of voting stock), held by non-affiliates is $1,138,402,886 based on the last reported sale price thereof on the consolidated tape on June 30, 2007.

As of January 31, 2008, 53,014,950 shares of Registrant s Common Stock, no par value (the only class of common stock), were outstanding.

Documents Incorporated By Reference

Document	**Part of Form 10-K into Which Document is Incorporated**
Proxy Statement to be filed in connection with the annual meeting	Part III, Items 10, 11, 12, 13 and 14

of shareholders to be held May 8, 2008

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* = not an applicable item in the 2007 calendar year for the Company

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ACRONYMS AND TERMS

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

Acronym/Term	**Meaning**
aMW	- Average Megawatt - a measure of the average rate at which a particular generating source produces energy over a period of time
AFUDC	- Allowance for Funds Used During Construction; represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period
AM&D	- Advanced Manufacturing and Development, does business as METALfx
APB	- Accounting Principles Board
Advantage IQ	- Advantage IQ, Inc., provider of facility information and cost management services for multi-site customers throughout North America, subsidiary of Avista Capital
Avista Capital	- Parent company to the Company s non-utility businesses
Avista Corp.	- Avista Corporation, the Company
Avista Energy	- Avista Energy, Inc., an electricity and natural gas marketing, trading and resource management business, subsidiary of Avista Capital
Avista Utilities	- operating division of Avista Corp. comprising the regulated utility operations
BPA	- Bonneville Power Administration
Capacity	- the rate at which a particular generating source is capable of producing energy, measured in KW or MW
Cabinet Gorge	- the Cabinet Gorge Hydroelectric Generating Project, located on the Clark Fork River in Idaho
Colstrip	- the coal-fired Colstrip Generating Plant in southeastern Montana
Coyote Springs 2	- the natural gas-fired Coyote Springs 2 Generating Plant located near Boardman, Oregon
CT	- Combustion turbine
Deadband or ERM deadband	- the first $4.0 million in annual power supply costs above or below the amount included in base retail rates in Washington under the Energy Recovery Mechanism in the state of Washington.
Dekatherm	- Unit of measurement for natural gas; a dekatherm is equal to approximately one thousand cubic feet (volume) or 1,000,000 BTUs (energy)
DOE	- the state of Washington s Department of Ecology
Energy	- the amount of electricity produced or consumed over a period of time, measured in KWH or MWH
EITF	- Emerging Issues Task Force
ERM	- the Energy Recovery Mechanism in the state of Washington

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FASB	- Financial Accounting Standards Board
FIN	- Financial Accounting Standards Board Interpretation
FERC	- Federal Energy Regulatory Commission
IPUC	- Idaho Public Utilities Commission
Jackson Prairie	- Jackson Prairie Natural Gas Storage Project, an underground natural gas storage field located near Chehalis, Washington
KV	- Kilovolt or 1000 volts, a measure of capacity on transmission lines
KW, KWH	- Kilowatt or 1000 watts a measure of generating output, kilowatt-hour or 1000 watt hours a measure of energy produced
Lancaster Plant	- a natural gas-fired combined cycle combustion turbine plant located in Idaho
MW, MWH	- Megawatt or 1000 KW, megawatt-hour or 1000 KWH
NERC	- North American Electricity Reliability Council
Noxon Rapids	- the Noxon Rapids Hydroelectric Generating Project, located on the Clark Fork River in Montana
OASIS	- Open Access Same-Time Information System
OPUC	- The Public Utility Commission of Oregon
PCA	- the Power Cost Adjustment mechanism in the state of Idaho
PLP	- Potentially liable party
PUD	- Public Utility District
PURPA	- the Public Utility Regulatory Policies Act of 1978
RTO	- Regional Transmission Organization
SFAS	- Statement of Financial Accounting Standards
Spokane River Project	- the five hydroelectric plants operating under one FERC license on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls)
Therm	- Unit of measurement for natural gas; a therm is equal to approximately one hundred cubic feet (volume) or 100,000 BTUs (energy)
Watt	- Unit of measurement for electricity; a watt is equal to the rate of work represented by a current of one ampere under a pressure of one volt
WUTC	- Washington Utilities and Transportation Commission

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PART I

Our Annual Report on Form 10-K contains forward-looking statements, which should be read with the cautionary statements and important factors included at Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Forward-Looking Statements on pages 23-24. 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, for predicts, and similar expressions. Forward-looking statements are subject to a variety of risks and uncertainties and other factors. Many of these factors are beyond our control and could have a significant effect on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in our statements.

Available Information

Our Web site address is www.avistacorp.com. We make annual, quarterly and current reports available at our Web site as soon as practicable after electronically filing these reports with the Securities and Exchange Commission. Information contained on our Web site is not part of this report.

Item 1. Business
Company Overview

Avista Corporation (Avista Corp. or the Company), incorporated in the state of Washington in 1889, is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. As of December 31, 2007, we employed 1,473 people in our utility operations and 644 people in our subsidiary businesses. Our corporate headquarters are in Spokane, Washington, the hub of the Inland Northwest. Agriculture, mining and lumber were the primary industries in the Inland Northwest for many years; today health care, education, finance, electronic and other manufacturing, tourism and the service sectors are growing in importance.

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

We have three reportable business segments as follows:

Avista Utilities an operating division of Avista Corp. comprising our regulated utility operations that started in 1889. Our utility generates, transmits and distributes electricity and distributes natural gas. The utility also engages in wholesale purchases and sales of electricity and natural gas.

Energy Marketing and Resource Management electricity and natural gas marketing, trading and resource management. The activities of this business segment were conducted primarily by Avista Energy, Inc. (Avista Energy), an indirect subsidiary of Avista Corp. On June 30, 2007, Avista Energy and Avista Energy Canada, Ltd. (Avista Energy Canada) completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy. Completion of this transaction effectively ends the majority of the operations of this business segment. This segment still owns natural gas storage facilities and has operating revenues and resource costs related to the power purchase agreement for a 270 megawatt (MW) natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant). The Lancaster Plant is owned by an unrelated third-party and all of the output from the plant is contracted to Avista Energy through 2026. The majority of the rights and obligations of the power purchase agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, we expect these rights and obligations will be transferred to Avista Utilities, subject to future regulatory approval. The operations of Avista Power, LLC (Avista Power), which are not significant to our overall operations at this time and are not expected to be in the future, are also included in this segment. Avista Power, through its equity investment in Rathdrum Power, LLC (RP LLC) was a 49 percent owner of the Lancaster Plant. In October

2006, Avista Power completed the sale of its investment in RP LLC for close to book value.

Advantage IQ a provider of facility information and cost management services for multi-site customers throughout North America. This segment s primary product lines include consolidated billing, resource accounting, energy analysis and load profiling services. The activities of this business segment are conducted by Advantage IQ, Inc. (Advantage IQ), an indirect subsidiary of Avista Corp.

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We have other businesses including sheet metal fabrication, venture fund investments and real estate investments. These activities do not represent a reportable business segment and are conducted by various indirect subsidiaries of Avista Corp., including Advanced Manufacturing and Development (AM&D), doing business as METALfx. Over time as opportunities arise, we plan to dispose of assets and phase out operations that do not fit with our overall corporate strategy. However, we may invest incremental funds to protect our existing investments and invest in new businesses that fit with our overall corporate strategy.

Avista Energy, Advantage IQ and the various other companies are subsidiaries of Avista Capital, Inc. (Avista Capital), which is wholly owned by Avista Corp. Our total common stockholders equity was $914.0 million as of December 31, 2007, of which $71.4 million represented our investment in Avista Capital. Our investment in Avista Capital decreased significantly in 2007 primarily due to the sale of substantially all of Avista Energy s contracts and ongoing operations and the subsequent dividends to Avista Corp. through Avista Capital.

Our organization is illustrated below:

AVA Formation Corp. (AVA) is the company formed for purposes of completing the proposed statutory share exchange and holding company implementation. AVA is currently a subsidiary of Avista Corporation. For further information, see Note 26 of the Notes to Consolidated Financial Statements.

See Item 6. Selected Financial Data and Note 29 of the Notes to Consolidated Financial Statements for information with respect to the operating performance of each business segment (and other subsidiaries).

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Avista Utilities

General

Through our regulated utility operations, we generate, transmit and distribute electricity and distribute natural gas. Retail electric and natural gas customers include residential, commercial and industrial classifications. We also engage in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and our load-serving obligation.

Our utility provides electric distribution and transmission, as well as natural gas distribution services in parts of eastern Washington and northern Idaho. We also provide natural gas distribution service in parts of northeast and southwest Oregon. At the end of 2007, we supplied retail electric service to 352,000 customers and retail natural gas service to 311,000 customers across our entire service territory. See Item 2. Properties for further information with respect to our utility assets.

Electric Operations

In addition to providing electric distribution and transmission services, we generate electricity from facilities that we own. In addition to resources that we own, we purchase capacity and energy under long-term and short-term contracts. We also sell capacity and energy from time to time in the wholesale market in connection with our resource optimization activities as described below.

We engage in an ongoing process of resource optimization. This involves the economic selection from available resources to serve load obligations and use existing resources to capture available economic value. We sell and purchase wholesale electric capacity and energy and fuel as part of the process of acquiring resources to serve our load obligations. These transactions range from terms of one hour up to multiple years. We make continuing projections of:

- 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, we make purchases and sales of energy to match expected resources to expected electric load requirements. Resource optimization involves our generating plant dispatch and scheduling available resources, and also includes transactions such as:

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

The optimization process includes entering into hedging transactions to manage risks.

Our generation assets are interconnected through the regional transmission system and are operated on a coordinated basis to enhance load-serving capability and reliability. We provide transmission and ancillary services in eastern Washington, northern Idaho and western Montana. Our Open Access Same-Time Information System (OASIS) is part of the Joint Transmission Services Information Network that covers much of the United States. Transmission revenues were $10.6 million in 2007, $10.5 million in 2006 and $11.0 million in 2005. In 2007, we completed a multi-year transmission system enhancement project at a total cost of $131 million.

Electric Requirements

Our peak electric native load requirement for 2007 occurred on January 12, 2007 at which time our total load was 2,052 MW consisting of:

- native load of 1,685 MW,
- long-term wholesale obligations of 242 MW, and
- short-term wholesale obligations of 125 MW.

At that time our maximum resource capacity available was 2,302 MW, which included:

- 1,447 MW of company-owned electric generation,
- 171 MW of long-term hydroelectric contracts with certain Public Utility Districts (PUDs),
- 359 MW of other long-term wholesale contracts, and

325 MW of short-term wholesale purchases.

Electric Resources

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

At the end of 2007, our facilities had a total net capability of 1,771 MW, of which 55 percent was hydroelectric and 45 percent was thermal. See Item 2. Properties for detailed information with respect to generating facilities.

Hydroelectric Resources We own and operate six hydroelectric projects on the Spokane River and two hydroelectric projects on the Clark Fork River. Hydroelectric generation is our lowest cost source per megawatt-hour (MWh) of electricity and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, we estimate that we would be able to meet approximately one-half of our total average electric requirements (both retail and long-term wholesale) with the combination of our hydroelectric generation and long-term hydroelectric purchase contracts with certain PUDs in the state of Washington. Our estimate of normal annual hydroelectric generation (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 538 average megawatts (aMW) (or 4.7 million MWhs). Hydroelectric resources provided 519 aMW for 2007, 561 aMW for 2006 and 511 aMW for 2005.

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

	2007	2006	2005
Noxon Rapids	1,591	1,824	1,589
Cabinet Gorge	1,088	1,146	1,004
Post Falls	83	97	87
Upper Falls	63	69	71
Monroe Street	100	106	101
Nine Mile	100	110	107
Long Lake	471	553	460
Little Falls	193	223	192
Total company-owned hydroelectric generation	3,689	4,128	3,611
Long-term hydroelectric contracts with PUDs	861	787	864
Total hydroelectric generation	4,550	4,915	4,475

Thermal Resources We own:

the combined cycle combustion turbine (CT) natural gas-fired Coyote Springs 2 Generation Project (Coyote Springs 2) located near Boardman, Oregon,

a 15 percent interest in a twin-unit, coal-fired boiler generating facility, the Colstrip 3 & 4 Generating Project (Colstrip) in southeastern Montana,

a wood waste-fired boiler generating facility known as the Kettle Falls Generating Station (Kettle Falls GS) in northeastern Washington,

- a two-unit natural gas-fired CT generating facility, located in northeast Spokane (Northeast CT),

- a two-unit natural gas-fired CT generating facility in northern Idaho (Rathdrum CT), and

- two small natural gas-fired generating facilities (Boulder Park and Kettle Falls CT).

Coyote Springs 2, which is operated by Portland General Electric Corporation, is supplied with natural gas under both term contracts and spot market purchases, including transportation agreements with unilateral renewal rights.

Colstrip, which is operated by PPL Montana, LLC, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements in effect through 2019.

The primary fuel for the Kettle Falls GS is wood waste generated as a by-product and delivered by trucks from forest industry operations within 100 miles of the plant. Natural gas may be used as an alternate fuel. A combination of long-term contracts and spot purchases has provided, and is expected to meet fuel requirements for the Kettle Falls GS.

The Northeast CT, Rathdrum CT, Boulder Park and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. We also operate these facilities when marginal costs are below prevailing wholesale electric prices. We did not operate these generating units significantly in 2007, 2006 and 2005. These generating facilities have access to natural gas supplies that are adequate to meet their respective operating needs.

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

	2007	2006	2005
Coyote Springs 2	1,623	1,459	1,528
Colstrip	1,673	1,579	1,771
Kettle Falls GS	299	354	338
Northeast CT and Rathdrum CT	20	24	6
Boulder Park and Kettle Falls CT	25	18	23
Total thermal generation	3,640	3,434	3,666

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

Pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA), we are required to purchase generation from qualifying facilities, including small hydroelectric and cogeneration projects, at rates approved by the Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC). These contracts expire at various times between 2015 and 2027. In February 2006, the PURPA was amended by the Federal Energy Regulatory Commission (FERC) as required by the Energy Policy Act of 2005. These amendments are not expected to have an effect on our PURPA-related contracts.

See Avista Utilities Operating Statistics Electric Operations Electric Energy Resources for annual quantities of purchased power, wholesale power sales and power from exchanges in 2007, 2006 and 2005.

Hydroelectric Relicensing

We are a licensee under the Federal Power Act as administered by the FERC, which includes regulation of hydroelectric generation resources. Except for the Little Falls Plant, all of our hydroelectric plants are regulated by the FERC through project licenses. The licensed projects are subject to the provisions of Part I of the Federal Power Act. These provisions include payment for headwater benefits, condemnation of licensed projects upon payment of just compensation, and take-over of such projects after the expiration of the license upon payment of the lesser of net investment or fair value of the project, in either case, plus severance damages.

In March 2001, we received a 45-year operating license from the FERC for the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) and the Noxon Rapids Hydroelectric Generating Project (Noxon Rapids). The Clark Fork Settlement Agreement that was entered into during 1999 and incorporated into the FERC license preserved the projects economic peaking and load following operations. Also, as part of the Clark Fork Settlement Agreement, we initiated the implementation of protection, mitigation and enhancement measures in March 1999. Measures in the agreement address issues related to fisheries, water quality, wildlife, recreation, land use, cultural resources and erosion.

See Clark Fork Settlement Agreement in Note 25 of the Notes to Consolidated Financial Statements for disclosure of dissolved atmospheric gas levels that exceed state of Idaho and federal water quality standards downstream of Cabinet Gorge during periods when we must divert excess river flows over the spillway and our mitigation plans and efforts.

Five of our hydroelectric plants on the Spokane River (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. Our other plant on the Spokane River, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. We filed a Notice of Intent to Relicense the Spokane River Project in July 2002. The formal consultation process involving planning and information gathering with stakeholder groups has been underway since that time. We filed our new license applications with the FERC in July 2005. Since we did not receive new license orders prior to the August 1, 2007 expiration of the current license, an annual license has been issued, in effect extending the current license and its conditions until August 1, 2008. We have no reason to believe that Spokane River Project operations will be interrupted in any manner relative to the timing of the FERC s actions. We have been engaged in a multi-year collaborative process with stakeholders to develop reasonable terms and conditions for the new licenses. We have requested the FERC to consider a license for Post Falls, which has a present capability of 18 MW and is located in Idaho, that is separate from the other four hydroelectric plants. This is because Post Falls presents more complex issues that may take longer to resolve than those relating to the rest of the Spokane River Project. If granted, new licenses would have a term of 30 to 50 years. In the license applications, we proposed a number of measures intended to address the impact of the Spokane River Project and enhance resources associated with the Spokane River.

We plan to request regulatory approval to recover licensing costs. For further information on the relicensing process for the Spokane River Project, see Spokane River Relicensing in Note 25 of the Notes to Consolidated Financial Statements.

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Future Resource Needs

We have operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed over hourly, daily, monthly and annual durations, which vary widely because of the factors that influence demand. The following is a forecast of our average annual energy requirements and resources for 2008, 2009, 2010 and 2011:

Forecasted Electric Energy Requirements and Resources

(aMW)

	2008	2009	2010	2011
Requirements:				
System load	1,105	1,118	1,141	1,161
Contracts for power sales	136	141	140	140
Total requirements	1,241	1,259	1,281	1,301
Resources:				
Company-owned and contract hydro generation (1)	541	540	526	524
Company-owned base load thermal generation (2)	258	242	246	256
Company-owned other thermal generation (2)	273	285	282	272
Contracts for power purchases	370	387	625	542
Total resources	1,442	1,454	1,679	1,594
Surplus resources	201	195	398	293
Additional available energy (3)	134	142	142	142
Total surplus resources	335	337	540	435

(1) The forecast assumes near normal hydroelectric generation of 541 aMW for 2008, 540 aMW for 2009, 526 aMW for 2010 and 524 aMW for 2011 (decline is related to changes in contracts with PUDs).

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

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

In September 2007, we submitted our 2007 Electric Integrated Resource Plan (IRP) to the WUTC and the IPUC. The IRP identifies a strategic resource portfolio that meets future electric load requirements, promotes environmental stewardship and meets our obligation to provide reliable electric service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project. Our preferred resource plan, which is part of the IRP, includes the addition of the following resources by 2017:

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

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

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

We are close to completing the acquisition of a wind generation site. We expect to construct a 50 MW generation facility in 2010 or 2011 at an estimated cost of approximately $120 million.

See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Environmental Issues and Other Contingencies for information with respect to a recently enacted law, as well as potential legislation that could influence our future electric resource mix.

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Natural Gas Operations

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

Market prices for natural gas continue to be competitive compared to alternative fuel sources for customers, and we believe that natural gas should sustain its long-term market advantage over competing energy sources based on the levels of existing reserves and potential natural gas development in the future.

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

As part of the process of balancing natural gas retail load requirements to resources obtained through wholesale purchases, we engage in wholesale sales of natural gas.

We also provide transportation service to certain large commercial and industrial natural gas customers who purchase natural gas through third party marketers. For these customers, we move their natural gas through our distribution system from the natural gas transmission pipeline delivery points to the customers premises. The total volume transported on behalf of our transportation customers for 2007, 2006 and 2005 was 148.8, 149.7 and 153.0 million therms. This represented 21 percent, 24 percent and 27 percent of total system deliveries.

Natural Gas Supply As we do not have any natural gas reserves, we purchase all of our natural gas in the wholesale market. We are connected to multiple supply basins in the western United States and western Canada through firm capacity delivery rights on five pipeline networks. Access to this diverse portfolio of natural gas resources allows us to make natural gas procurement decisions that benefit our natural gas customers. Historically, we have obtained approximately 25 percent of natural gas supplies from domestic sources, with the remaining 75 percent from Canadian sources. Natural gas prices in the Pacific Northwest are affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada. Future prices and delivery constraints may cause our source mix to vary.

Natural Gas Storage We own a one-third interest in the Jackson Prairie Natural Gas Storage Project (Jackson Prairie), an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 8.8 million therms, with a total working natural gas inventory of 234.3 million therms. The role of Jackson Prairie in providing flexible natural gas supplies is important to our natural gas operations. It enables us to place natural gas into storage when prices are lower or to satisfy minimum natural gas purchasing requirements, as well as to meet high demand periods or to withdraw natural gas from storage when spot prices are higher.

In prior years, we released 27.5 million therms of then unneeded Jackson Prairie capacity to two other utilities under long-term contracts. In 2006, we recalled both releases, resulting in 17 percent of the released capacity returned to us during 2007 and the remaining 83 percent to be returned during 2008.

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

Regulatory Issues

General As a regulated public utility, we are subject to regulation by state utility commissions with respect to prices, accounting, the issuance of securities, and other matters. The retail electric and natural gas operations are subject to the jurisdiction of the WUTC, the IPUC, the Public Utility Commission of Oregon (OPUC), and the Public Service Commission of the State of Montana (Montana Commission). Approval of the issuance of securities is not required from the Montana Commission. We are also subject to the jurisdiction of the FERC for wholesale natural gas rates charged for the release of capacity from Jackson Prairie, licensing of hydroelectric generation resources, and for electric transmission service and wholesale sales.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a cost of service basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for us to earn a reasonable return on rate base. Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and retirement of utility plant and

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write-offs as authorized by the utility commissions. Our rates for wholesale electric and natural gas transmission services are based on either cost of service principles or market-based rates as set forth by the FERC. See Note 1 of Notes to Consolidated Financial Statements for additional information about regulation, depreciation and deferred income taxes. See Industry Developments for additional information about deregulation, as well as changes with respect to transmission and wholesale electricity markets.

General Rate Cases We regularly review the need for electric and natural gas rate changes in each state in which we provide service. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Avista Utilities Regulatory Matters General Rate Cases for information on general rate case activity.

Power Cost Deferrals We defer the recognition in the income statement of certain power supply costs that vary from the level currently recovered from our retail customers as authorized by the WUTC and the IPUC. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Avista Utilities Regulatory Matters Power Cost Deferrals and Recovery Mechanisms and Note 1 - Power Cost Deferrals and Recovery Mechanisms of the Notes to Consolidated Financial Statements for detailed information on power cost deferrals and recovery mechanisms in Washington and Idaho.

Purchased Gas Adjustment (PGA or Natural Gas Trackers) Under established regulatory practices in each respective state, we are allowed to adjust natural gas rates periodically (with regulatory approval) to reflect increases or decreases in the cost of natural gas purchased. Differences between actual natural gas costs and the natural gas costs included in retail rates are deferred and charged or credited to expense when regulators approve inclusion of the cost changes in rates. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Avista Utilities Regulatory Matters Purchased Gas Adjustments Note 1 Natural Gas Cost Deferrals and Recovery Mechanisms of the Notes to Consolidated Financial Statements for detailed information on natural gas cost deferrals and recovery mechanisms in Washington, Idaho and Oregon.

Industry Developments

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

- reform of the hydroelectric licensing process,
- tax credits for incremental hydroelectric production placed into service before 2009, and
- the implementation of mandatory reliability standards.

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

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

The implementation of the Energy Policy Act requires proceedings at the state level and the development of regulations by the FERC, the Department of Energy and other federal agencies. Certain provisions of the Energy Policy Act expire at the end of 2008.

Federal Initiatives Related to Wholesale Competition Industry restructuring to open the electric wholesale energy market to competition is promoted by federal legislation. The Energy Policy Act of 1992 expanded the authority of the FERC to require electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and to require electric utilities to enhance or construct transmission facilities to create additional transmission capacity for the purpose of providing these services. Public utilities (through subsidiaries) and other entities may participate in the development of independent electric generating plants for sales to wholesale customers.

FERC rules issued in the mid-1990s require public utilities operating under the Federal Power Act to provide open and non-discriminatory access to their transmission systems to third parties and establish an OASIS to provide an electronic means by which transmission customers can attain information about available transmission capacity and purchase transmission access. The FERC also requires each public utility subject to the rules to functionally separate its transmission and wholesale power merchant functions and comply with standards of conduct designed to ensure that all wholesale users, including the public utility s power merchant function, have equal access to the public utility s transmission system. Our compliance with these standards has not had any substantive impact on the operation, maintenance and marketing of our transmission system or our ability to provide service to customers.

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Regional Transmission Organizations FERC Order No. 2000 (issued in 2000) required all utilities subject to FERC regulation to file a proposal to form a Regional Transmission Organization (RTO), or a description of efforts to participate in an RTO, and any existing obstacles to RTO participation. While it has not formally withdrawn Order No. 2000, the FERC has issued orders and made public policy statements indicating its support for the development and formation of regional independently-governed transmission organizations developed by such regions, but that do not necessarily meet all of the RTO functions and characteristics outlined in Order No. 2000.

We have participated in discussions with transmission providers and other stakeholders in the Pacific Northwest for several years regarding the possible formation of an RTO in the region. ColumbiaGrid, a Washington nonprofit membership corporation, was formed to improve the operational efficiency, reliability, and planned expansion of the transmission grid in the Pacific Northwest. ColumbiaGrid members, including Avista Corp., elected an independent slate of directors to a three-member board in August 2006. ColumbiaGrid s responsibilities and related agreements with its members are currently being developed in a public process with broad participation. ColumbiaGrid s transmission planning and expansion functional agreement was accepted by the FERC and has been signed by a number of Pacific Northwest parties, including Avista Corp. We will continue to assess the benefits of entering into other functional agreements with ColumbiaGrid.

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

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

On March 15, 2007, the FERC approved 83 NERC Reliability Standards and six regional differences, the first set of legally enforceable standards for the United States bulk power system. These mandatory Reliability Standards became effective on June 18, 2007.

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

Environmental Issues

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

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

Fisheries A number of species of fish in the Northwest, including the Snake River sockeye salmon and fall chinook salmon, the Kootenai River white sturgeon, the upper Columbia River steelhead, the upper Columbia River spring chinook salmon and the bull trout, are listed as threatened or endangered under the Federal Endangered Species Act. Thus far, measures that were adopted and implemented to save the Snake River sockeye salmon and fall chinook salmon have not directly impacted generation levels at any of our hydroelectric facilities. We do, however, purchase power under long-term contracts with certain PUDs on the Columbia River that are directly impacted by ongoing mitigation measures for salmon and steelhead. The reduction in generation at these projects is relatively minor, resulting in minimal economic impact on our operations at this time. We cannot accurately predict the likely economic costs to us resulting from future actions. We received a 45-year FERC operating license for Cabinet Gorge and Noxon Rapids in March 2001 that incorporates a comprehensive settlement agreement. The restoration of native salmonid fish, particularly bull trout, is a key part of the agreement. The result is a collaborative bull trout recovery program with the U.S. Fish and Wildlife Service, Native American tribes and the states of Idaho and Montana on the lower Clark Fork River, consistent with requirements of the FERC license. See Hydroelectric Relicensing on page 5 for further information.

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Air Quality The most significant impact on us related to the Clean Air Act (CAA) and the 1990 Clean Air Act Amendments (CAAA) pertains to Colstrip, which is a Phase II coal-fired plant under the CAAA. We do not expect Colstrip to be required to implement any additional sulfur dioxide (SO2) mitigation in the foreseeable future in order to continue operations. Our other thermal projects are subject to various CAAA standards. Every five years each of the other thermal projects requires an updated operating permit (known as a Title V permit), which addresses, among other things, the compliance of the plant with the CAAA. The operating permit for the Rathdrum CT was renewed in 2006 (expires in 2011) and the operating permit for the Kettle Falls GS was renewed in 2007 (expires in 2012). The Northeast CT was issued a Title V permit in February 2004 (expires in 2009). Boulder Park does not require a Title V permit based on its limited output and instead has a synthetic minor permit that does not expire. Coyote Springs 2 has a Title V permit that was issued in 2003 (expires in 2008) and we have applied for renewal.

The EPA issued mercury emission regulations that will affect coal-fired generation plants, including Colstrip. The new EPA regulations establish an emission trading program to take effect beginning in January 2010, with a second phase to take effect in 2018. In addition, in 2006, the Montana Department of Environmental Quality (DEQ) adopted final rules for the control of mercury emissions from coal-fired plants that are more restrictive than EPA regulations. The new rules set strict mercury emission limits by 2010, and put in place a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities. In February 2008, the United States Court of Appeals for the District of Columbia overturned the EPA s mercury emissions regulations. However, this ruling is not expected to affect our current plans to comply with the more restrictive regulations adopted by the Montana DEQ as described below.

The owners of Colstrip completed the first phase of testing on two mercury control technologies. Although the mercury reduction targets as mandated by the Montana DEQ have not been achieved, the owners of Colstrip are encouraged with the preliminary results and believe it should be possible to achieve the required emissions levels with further mercury control system optimization. Preliminary estimates indicate that our share of installation capital costs would be $1.3 million and annual operations and maintenance costs would increase by $2.8 million (beginning in mid-2009). We will continue to seek recovery, through the rate making process, of the costs to comply with various air quality requirements.

Water Quality See Clark Fork Settlement Agreement in Note 25 of the Notes to Consolidated Financial Statements regarding dissolved atmospheric gas levels that exceed state of Idaho and federal water quality standards downstream of Cabinet Gorge. See Spokane River Relicensing in Note 25 of the Notes to Consolidated Financial Statements for the pending Clean Water Act certifications for our relicensing of the Spokane River Project.

Other Environmental Issues See Colstrip Generating Project Complaint, Harbor Oil Inc. Site, and Northeast Combustion Turbine Site in Note 25 of the Notes to Consolidated Financial Statements for information with respect to additional environmental issues.

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AVISTA UTILITIES OPERATING STATISTICS

	Years Ended December 31,		
	2007	**2006**	**2005**
ELECTRIC OPERATIONS			
ELECTRIC OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 251,357	$ 234,714	$ 211,934
Commercial	224,179	221,193	203,480
Industrial	95,207	92,961	91,552
Public street and highway lighting	5,517	5,268	4,898
Total retail revenues	576,260	554,136	511,864
Wholesale revenues	105,729	126,208	151,429
Revenues from sales of fuel	12,910	48,176	41,831
Other revenues	16,231	18,863	17,988
Total electric operating revenues	$ 711,130	$ 747,383	$ 723,112
ELECTRIC ENERGY SALES (Thousands of MWhs):			
Residential	3,670	3,578	3,420
Commercial	3,132	3,110	2,994
Industrial	2,084	2,062	2,091
Public street and highway lighting	26	25	25
Total retail energy sales	8,912	8,775	8,530
Wholesale energy sales	1,594	2,117	2,508
Total electric energy sales	10,506	10,892	11,038
ELECTRIC ENERGY RESOURCES (Thousands of MWhs):			
Hydro generation (from Company facilities)	3,689	4,128	3,611
Thermal generation (from Company facilities)	3,640	3,434	3,666
Purchased power - hydro generation from long-term contracts with PUDs	861	787	864
Purchased power - wholesale	2,959	3,101	3,519
Power exchanges	(18)	35	10
Total power resources	11,131	11,485	11,670
Energy losses and Company use	(625)	(593)	(632)
Total energy resources (net of losses)	10,506	10,892	11,038
NUMBER OF ELECTRIC RETAIL CUSTOMERS (Average for Period):			
Residential	306,737	300,940	294,036
Commercial	38,488	37,912	37,282
Industrial	1,378	1,388	1,408
Public street and highway lighting	426	425	421
Total electric retail customers	347,029	340,665	333,147

ELECTRIC RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (KWh)	11,965	11,888	11,630
Revenue per KWh (in cents)	6.85	6.56	6.20
Annual revenue per customer	$ 819.45	$ 779.94	$ 720.78
ELECTRIC AVERAGE HOURLY LOAD (aMW)	1,089	1,069	1,046
RESOURCE AVAILABILITY at time of system peak (MW):			
Total requirements (winter):			
Retail native load	1,685	1,656	1,660
Wholesale obligations	367	431	282
Total requirements (winter)	2,052	2,087	1,942
Total resource availability (winter)	2,302	2,618	2,556
Total requirements (summer):			
Retail native load	1,631	1,643	1,498
Wholesale obligations	381	588	575
Total requirements (summer)	2,012	2,231	2,073
Total resource availability (summer)	2,434	2,551	2,519
COOLING DEGREE DAYS: (1)			
Spokane, WA			
Actual	576	615	409
30-year average	394	394	394
% of average	146%	156%	104%

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

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AVISTA UTILITIES OPERATING STATISTICS

	Years Ended December 31,		
	2007	**2006**	**2005**
NATURAL GAS OPERATIONS			
NATURAL GAS OPERATING REVENUES (Dollars in Thousands):			
Residential	$ 264,546	$ 257,753	$ 229,737
Commercial	148,416	146,581	126,648
Industrial and interruptible	11,284	11,676	11,867
Total retail natural gas revenues	424,246	416,010	368,252
Wholesale revenues	142,167	93,221	58,074
Transportation revenues	6,638	6,499	7,601
Other revenues	4,182	4,825	4,278
Total natural gas operating revenues	$ 577,233	$ 520,555	$ 438,205
THERMS DELIVERED (Thousands of Therms):			
Residential	195,756	192,833	199,433
Commercial	121,557	120,989	122,981
Industrial and interruptible	10,833	11,040	13,534
Total retail	328,146	324,862	335,948
Wholesale	223,084	154,884	72,903
Transportation	148,765	149,717	152,990
Interdepartmental and Company use	438	443	466
Total therms delivered	700,433	629,906	562,307
SOURCES OF NATURAL GAS SUPPLY (Thousands of Therms):			
Purchases	561,277	483,038	418,739
Storage - injections	(35,228)	(17,892)	(26,359)
Storage - withdrawals	28,842	18,181	20,814
Natural gas for transportation	148,765	149,717	152,990
Distribution system losses	(3,223)	(3,138)	(3,877)
Total natural gas supply	700,433	629,906	562,307
NUMBER OF NATURAL GAS RETAIL CUSTOMERS (Average for Period):			
Residential	273,415	267,345	265,294
Commercial	32,327	31,746	31,652
Industrial and interruptible	302	295	307
Total natural gas retail customers	306,044	299,386	297,253
NATURAL GAS RESIDENTIAL SERVICE AVERAGES:			
Annual use per customer (therms)	716	721	752
Revenue per therm (in dollars)	$ 1.35	$ 1.34	$ 1.15
Annual revenue per customer	$ 967.56	$ 964.12	$ 865.97

SYSTEM MAXIMUM CAPABILITY (Thousands of Therms):			
System maximum demand (winter)	3,464	2,650	2,698
System maximum firm contractual capacity (winter)	4,519	4,549	4,340
HEATING DEGREE DAYS: (1)			
Spokane, WA			
Actual	6,539	6,332	6,538
30-year average	6,820	6,820	6,820
% of average	96%	93%	96%
Medford, OR			
Actual	4,386	4,167	4,185
30-year average	4,533	4,533	4,533
% of average	97%	92%	92%

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

AVISTA CORPORATION

Energy Marketing and Resource Management

This segment primarily includes the results of Avista Energy. On June 30, 2007, Avista Energy and its subsidiary, Avista Energy Canada, completed the sale of substantially all of their contracts and ongoing operations to Shell Energy, as well as to certain other subsidiaries of Shell Energy. Completion of this transaction effectively ends the majority of the operations of this business segment. Avista Energy Canada provided natural gas services to industrial and commercial customers in British Columbia, Canada.

The historical activities of Avista Energy included:

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

Advantage IQ

Our subsidiary, Advantage IQ, is a provider of facility information and cost management services for multi-site customers throughout North America. Through invoice processing, auditing, payment services and comprehensive reporting, our solutions at Advantage IQ are designed to provide companies with critical and easy-to-access information that enables them to proactively manage and reduce their utility, telecom and waste management expenses.

As part of this process, Advantage IQ analyzes and audits invoices, then presents consolidated bills on-line, as well as processing payments for these expenses. Information gathered from invoices, providers and other customer-specific data allows Advantage IQ to provide our clients with in-depth analytical support, real-time reporting and consulting services.

Advantage IQ secured five patents on its two critical business systems:

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

We are not aware of any claimed or threatened infringement on any of Advantage IQ s patents issued to date and we expect to continue to expand and protect existing patents, as well as file additional patent applications for new products, services and process enhancements.

The following table presents key statistics for Advantage IQ:

	2007	2006	2005
Customers at year-end	403	373	348
Billed sites at year-end (1)	199,088	199,752	174,910
Dollars of customer bills processed (in billions)	$ 12.5	$ 10.8	$ 9.3

(1) The number of billed sites decreased slightly from 2006 to 2007. This decrease was due to the loss of a customer that had a significant number of billed sites, and represented approximately 1 percent of annualized revenues.

Other Businesses

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

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

Over time as opportunities arise, we plan to dispose of assets and phase out operations that do not fit with our overall corporate strategy. However, we may invest incremental funds to protect our existing investments and invest in new businesses that fit with our overall corporate strategy.

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Item 1A. Risk Factors
Risk Factors

The following factors could have a significant impact on our operations, results of operations, financial condition or cash flows. These factors could cause actual results or outcomes to differ materially from those discussed in our reports filed with the Securities and Exchange Commission (including this Annual Report on Form 10-K), and elsewhere. Please also see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations - Forward-Looking Statements for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements.

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

Weather has a significant effect on our utility operations, including impacting customer demand and operating revenues. We normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce operating revenues. In addition, below normal precipitation (particularly winter snowpack) and other streamflow conditions can negatively impact our electric resource costs by decreasing hydroelectric generation capability and increasing our reliance on market purchases and thermal generation. Regional precipitation and snowpack conditions typically have a significant effect on the wholesale price of electricity. In addition, high demand for electricity will generally increase both the quantity needed and price of fuel for generation and wholesale market prices.

We are subject to commodity price risk.

Our utility activities are subject to electric and natural gas commodity price risk. In general, price risk is driven by fluctuation in the market price of the commodity needed, held or traded. Adverse changes in wholesale energy prices can affect, among other things, the cash requirements to purchase electricity and natural gas for retail customers or wholesale obligations, as well as the market value of derivative assets and liabilities.

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

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

- disruptions of or constraints on transmission facilities.

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

- adequacy of North American production,
- level of imports,
- inventory levels and regional accessibility,
- demand for natural gas, including natural gas as fuel for electric generation,
- the number of market participants and the willingness of market participants to trade,
- global energy markets, including oil or other natural gas substitutes, and
- availability of pipeline capacity to transport natural gas from region to region.

Any combination of these factors that results in a shortage of energy generally causes the market price to move upward.

Increasing energy commodity prices have a significant effect on our liquidity. We have regulatory mechanisms in place that provide for the deferral and recovery of the majority of utility power and natural gas supply costs. However, if prices increase above the level currently recovered in retail rates during periods when we must purchase power and natural gas for generation and retail natural gas loads, power and natural gas deferral balances will increase. This will negatively affect our operating cash flow and liquidity until such costs are recovered from customers.

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Deferred power and natural gas costs are subject to regulatory review; costs higher than those recovered in base rates reduce cash flows, and it may take several years for us to recover deferred costs.

We defer income statement recognition of certain power and natural gas costs that are higher than what is currently recovered from our retail customers as authorized by regulators. These excess power and natural gas costs are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and for the potential of disallowance by state regulators.

Despite the opportunity to eventually recover a substantial portion of power and natural gas costs, our operating cash flows are negatively affected until these costs are recovered from customers. Factors that could cause costs to exceed the levels recovered from customers include, but are not limited to, higher prices in wholesale markets when we buy energy or an increased need to purchase energy in the wholesale markets. Factors beyond our control that could result in an increased need to purchase energy in the wholesale markets include, but are not limited to:

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

We are subject to the risk that regulators will not grant timely or sufficient recovery of our costs and not provide a reasonable rate of return for our shareholders.

We regularly review the need for electric and natural gas rate changes in each state in which we provide service. We will continue to periodically file for rate increases with regulatory agencies to recover our costs and provide a reasonable return to our shareholders. If regulators were to grant substantially lower rate increases than our requests in the future, it could have a negative effect on our operating revenues, net income and cash flows.

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

We have six hydroelectric plants on the Spokane River, and five of these are under one FERC license. Collectively, these five plants are referred to as the Spokane River Project. Since we did not receive new license orders prior to the August 1, 2007 expiration of the current license, an annual license was issued, in effect extending the current license and its conditions until August 1, 2008.

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

We are subject to credit risk.

Credit risk relates to the losses that we would incur as a result of non-performance of contractual obligations by counterparties to deliver energy or make financial settlements. We often extend credit to counterparties and customers, and we are exposed to the risk of not being able to collect amounts owed to us. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when we establish conservative credit limits. Credit risk includes the risk that a counterparty may default due to circumstances:

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

Should a counterparty, customer or supplier fail to perform, we may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices.

Credit risk also involves the exposure that counterparties perceive related to our ability to perform deliveries and settlement under physical and financial energy contracts. These counterparties may seek assurances of performance in the form of letters of credit, prepayment, or cash deposits.

Credit exposure can change significantly in periods of price volatility. As a result, sudden and significant demands may be made against our credit facilities and cash.

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

Although we engage in active hedging and resource optimization practices, we cannot and do not attempt to fully hedge our energy resource assets or our forecasted net positions for various time horizons, and our hedging procedures may not fully match the corresponding purchase or sale. To reduce financial and economic exposure related to commodity price fluctuations, we routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity and natural gas, as well as forecasted excess or deficit energy positions and inventories of natural gas. We utilize physical energy contracts and derivative instruments, such as forwards, futures, swaps and options traded in the over-the-counter markets or on exchanges. However, we do not cover the entire exposure of our forecasted net positions to market price volatility and the coverage will vary over time. To the extent we have unhedged positions, or if hedging positions do not fully match the corresponding purchase or sale, fluctuating commodity prices could have a material adverse effect on our operating revenues, resource costs, derivative assets and liabilities, and operating cash flows. In addition, actual loads and resources typically vary from forecasts, sometimes to a significant degree, which requires additional transactions or dispatch decisions that impact cash flows.

Risk management procedures may not prevent losses.

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

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

We need to maintain access to adequate levels of credit with banks for short-term liquidity. We have a $320 million committed line of credit, which is scheduled to expire in April 2011. We cannot predict whether we will have access to credit beyond the expiration date. The line of credit contains customary covenants and default provisions. In the event of default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock.

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

We need to access long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital from time to time. Our ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or prohibit our ability to finance capital expenditures and repay maturing long-term debt. Our liquidity needs could exceed our short-term credit availability and lead to defaults on various financing arrangements. We would also likely be prohibited from paying dividends on our common stock.

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

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

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

We expect utility capital expenditures to be $200 million for 2008, and over $200 million in each of 2009 and 2010. In addition to ongoing needs for our utility distribution system, significant projects include the continued

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enhancement of our transmission system and upgrades to generating facilities. We have $318 million of long-term debt maturities in 2008. Our forecasts indicate that we will issue new securities to fund a significant portion of these requirements. In 2004, we entered into forward-starting interest rate swap agreements to effectively lock in market fixed interest rates for $125 million of forecasted debt issuances in 2008. We also have $83.7 million of Pollution Control Bonds that are subject to remarketing on December 30, 2008. These bonds are puttable at the option of the security holders on that date. If the bonds cannot be successfully remarketed on that date, we will be required to purchase the outstanding bonds. In addition, we have $25 million of Secured Medium-Term Notes with a maturity date of June 2028 that are puttable at the option of the security holders in June 2008. Rising interest rates could increase future debt service costs and decrease operating cash flows to the extent we issue new securities to fund these obligations.

We are subject to various operational and event risks that are common to the utility industry.

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

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

We are currently the subject of several regulatory proceedings, and we are named in multiple lawsuits related to our participation in western energy markets as disclosed in Note 25 of the Notes to Consolidated Financial Statements.

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

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

As a result of these proceedings and complaints, certain parties have asserted claims for significant refunds and damages from us, which could result in a negative effect on our results of operations and cash flows. See Note 25 of the Notes to Consolidated Financial Statements for further information. Any potential refunds or obligations arising from western energy market issues (or any other contingent matters) were retained by Avista Energy.

We are subject to the risk of the potential effects from legislation or administrative rulemaking.

We expect to continue to be affected by legislation at the national, state and local level, as well as by administrative rules published by government agencies, such as the FERC, NERC and the EPA. Future legislation or administrative rules could have a material adverse effect on our operations, results of operations, financial condition and cash flows.

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

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

Environmental laws and regulations may have the effect of:

- increasing the costs of generating plants,
- increasing the lead time for the construction of new generating plants,

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

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

We have contingent liabilities, as disclosed in Note 25 of the Notes to Consolidated Financial Statements, and cannot predict the outcome of these matters.

We have multiple matters that are the subject of ongoing litigation, mediation, investigation and/or negotiation. We cannot predict the ultimate outcome or potential impact of any particular issue, including the extent, if any, of insurance coverage or that amounts payable by us may be recoverable through the rate making process. See Note 25 of the Notes to Consolidated Financial Statements for further details of these matters.

Lake Coeur d Alene Matter

We are liable for compensation (the amount is not yet determined) for the use of portions of the bed and banks of Lake Coeur d Alene and the St. Joe River. These beds and banks were determined to be the property of the Coeur d Alene Tribe of Idaho. We are in discussions with the Tribe concerning past and future compensation (which may include interest) for use of the portions of the beds and banks of the lake that are owned by the Tribe. If the parties cannot agree on the amount of compensation, the matter could result in litigation.

Other Environmental Matters

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

- we currently own,
- we have formerly owned or have used as a customer,
- are adjacent to our property,
- are located on the Spokane River, or

are downstream of our hydroelectric facilities and the resulting impact on free ranging fish.

Item 1B. Unresolved Staff Comments

As of the filing date of this Annual Report on Form 10-K, we have no unresolved comments from the staff of the Securities and Exchange Commission.

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Item 2. Properties
Avista Utilities

Substantially all of our utility properties are subject to the lien of our various mortgage indentures.

Our utility electric properties, located in the states of Washington, Idaho, Montana and Oregon, include the following:

Generation Properties

	No. of Units	Nameplate Rating (MW) (1)	Present Capability (MW) (2)
Hydroelectric Generating Stations (River)			
Washington:			
Long Lake (Spokane)	4	70.0	90.4
Little Falls (Spokane)	4	32.0	36.0
Nine Mile (Spokane)	4	26.4	15.0
Upper Falls (Spokane)	1	10.0	10.2
Monroe Street (Spokane)	1	14.8	15.0
Idaho:			
Cabinet Gorge (Clark Fork)	4	265.0	267.0
Post Falls (Spokane)	6	14.8	18.0
Montana:			
Noxon Rapids (Clark Fork)	5	473.4	527.0
Total Hydroelectric		906.4	978.6
Thermal Generating Stations			
Washington:			
Kettle Falls GS	1	50.7	50.0
Kettle Falls CT	1	6.9	6.9
Northeast CT	2	61.8	60.8
Boulder Park	6	24.6	24.6
Idaho:			
Rathdrum CT	2	166.5	149.0
Montana:			
Colstrip Units 3 and 4 (3)	2	233.4	222.0
Oregon:			
Coyote Springs 2	1	287.0	279.0
Total Thermal		830.9	792.3
Total Generation Properties		1,737.3	1,770.9

(1) Nameplate Rating, also referred to as installed capacity, is the manufacturer s assigned power capability under specified conditions.

(2)

Present capability is the maximum capacity of the plant under standard test conditions without exceeding specified limits of temperature, stress and environmental conditions. Information is provided as of December 31, 2007.

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

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Electric Distribution and Transmission Plant

We operate approximately 17,800 miles of primary and secondary electric distribution lines providing service to retail customers. We have an electric transmission system of approximately 600 miles of 230 kV line and 1,500 miles of 115 kV line. We also own an 11 percent interest (representing 465 MW of capacity) in approximately 500 miles of a 500 kV line between Colstrip, Montana and Townsend, Montana. Our transmission and distribution system also includes numerous substations with transformers, switches, monitoring and metering devices, and other equipment.

The 230 kV lines are the backbone of our transmission grid and are used to transmit power from generation resources to the major load centers in our service area, as well as to transfer power between points of interconnection with adjoining electric transmission systems. These lines interconnect at various locations with the BPA, Grant County PUD, PacifiCorp, NorthWestern Energy and Idaho Power Company. These interconnections serve as points of delivery for power from generating facilities outside of our distribution territory, including:

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

These lines also provide a means for us to optimize resources by entering into short-term purchases and sales of power with entities within and outside of the Pacific Northwest. We recently completed a $131 million project to enhance our 230 kV transmission system.

The 115 kV lines provide for transmission of energy and the integration of smaller generation facilities with our service-area load centers, including the Spokane River hydroelectric and the Kettle Falls GS. These lines interconnect with the BPA, Chelan County PUD, the Grand Coulee Project Hydroelectric Authority, Grant County PUD, NorthWestern Energy, PacifiCorp, Pend Oreille County PUD and Puget Sound Energy. Both the 115 kV and 230 kV interconnections with the BPA are used to exchange energy to facilitate service to each other s customers that are connected through the other s transmission system. We hold a long-term contract that allows us to serve our native load customers that are connected through the BPA s transmission system.

Natural Gas Plant

We have natural gas distribution mains of approximately 3,300 miles in Washington, 1,700 miles in Idaho and 1,900 miles in Oregon. The natural gas distribution system includes numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment.

We own a one-third interest in the Jackson Prairie Natural Gas Storage Project (Jackson Prairie), an underground natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 8.8 million therms, with a total working natural gas inventory of 234.3 million therms. The role of Jackson Prairie in providing flexible natural gas supplies is important to our natural gas operations. It enables us to place natural gas into storage when prices are lower or to satisfy minimum natural gas purchasing requirements, as well as to meet high demand periods or to withdraw natural gas from storage when spot prices are higher.

In prior years, we released 27.5 million therms of then unneeded Jackson Prairie capacity to two other utilities under long-term contracts. In 2006, we recalled both releases, resulting in 17 percent of the released capacity returned to us during 2007 and the remaining 83 percent to be returned during 2008.

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

Item 3. Legal Proceedings

See Note 25 of Notes to Consolidated Financial Statements for information with respect to legal proceedings.

Item 4. Submission of Matters to a Vote of Security Holders

None.

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PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is currently listed on the New York Stock Exchange. As of January 31, 2008, there were 12,902 registered shareholders of our common stock.

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

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

Our net income available for dividends has generally been derived from our regulated utility operations (Avista Utilities) and Avista Energy.

With the completion of the sale of contracts and the liquidation of Avista Energy s remaining net current assets, almost all of Avista Energy s cash was distributed to Avista Capital through a dividend of $169 million in September 2007. Avista Capital then paid a cash dividend of $155 million to Avista Corp. In December 2007, Avista Capital paid an additional $6 million dividend to Avista Corp. As such, the majority of the proceeds from the Avista Energy transaction were deployed into our regulated utility operations.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock contained in our Restated Articles of Incorporation, as amended, and to long-term debt contained in various indentures. Covenants under the 9.75 percent Senior Notes that mature on June 1, 2008 limit our ability to increase common stock cash dividends to no more than 5 percent over the previous quarter, unless certain conditions are met related to restricted payments. As of December 31, 2007, we met the conditions that would allow us to increase the common stock cash dividend in excess of 5 percent over the previous quarter.

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

As further discussed at Note 26 of the Notes to the Consolidated Financial Statements, the IPUC accepted a stipulation that we entered with the IPUC Staff that sets forth a variety of conditions if and when we implement a holding company structure. One of the conditions would require IPUC approval of any dividend to the holding company that would reduce utility common equity below 25 percent. We entered into a similar agreement in Washington. This agreement would require WUTC approval of any dividend to the holding company that would reduce utility common equity below 30 percent. The utility equity component was approximately 45 percent as of December 31, 2007.

For additional information, refer to Notes 1, 22, 23 and 24 of Notes to Consolidated Financial Statements. For high and low stock prices, as well as dividend information, refer to Note 30 of Notes to Consolidated Financial Statements.

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

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Item 6. Selected Financial Data
(in thousands, except per share data and ratios)

	Years Ended December 31,				
	2007	2006	2005	2004	2003
Operating Revenues:					
Avista Utilities	$ 1,288,363	$ 1,267,938	$ 1,161,317	$ 972,574	$ 928,211
Energy Marketing and Resource Management	61,541	177,551	167,439	275,646	307,141
Advantage IQ	47,255	39,636	31,748	23,444	19,839
Other	20,598	21,186	18,532	17,127	13,581
Intersegment Eliminations			(19,429)	(137,211)	(145,387)
Total	$ 1,417,757	$ 1,506,311	$ 1,359,607	$ 1,151,580	$ 1,123,385
Income (Loss) from Operations (pre-tax):					
Avista Utilities	$ 150,053	$ 177,049	$ 165,101	$ 134,073	$ 146,777
Energy Marketing and Resource Management	(22,366)	13,239	(18,267)	11,681	30,078
Advantage IQ	11,012	10,479	6,973	1,742	(1,331)
Other	(270)	(1,207)	(2,060)	(7,026)	(3,821)
Total	$ 138,429	$ 199,560	$ 151,747	$ 140,470	$ 171,703
Income (Loss) from Continuing Operations:					
Avista Utilities	$ 43,822	$ 57,794	$ 52,299	$ 32,467	$ 36,241
Energy Marketing and Resource Management	(11,877)	11,567	(8,621)	9,733	20,672
Advantage IQ	6,651	6,255	3,922	577	(1,334)
Other	(121)	(2,675)	(2,612)	(7,163)	(4,936)
Total	38,475	72,941	44,988	35,614	50,643
Loss from discontinued operations					(4,949)
Net income before cumulative effect of accounting change	38,475	72,941	44,988	35,614	45,694
Cumulative effect of accounting change				(460)	(1,190)
Net income	38,475	72,941	44,988	35,154	44,504
Preferred stock dividend requirements (1)					(1,125)
Income available for common stock	$ 38,475	$ 72,941	$ 44,988	$ 35,154	$ 43,379
Average common shares outstanding, basic	52,796	49,162	48,523	48,400	48,232
Average common shares outstanding, diluted	53,263	49,897	48,979	48,886	48,630
Common shares outstanding at year-end	52,909	52,514	48,593	48,472	48,344
Earnings per Common Share, Diluted:					
Earnings from continuing operations	$ 0.72	$ 1.46	$ 0.92	$ 0.73	$ 1.02
Loss from discontinued operations					(0.10)
Earnings before cumulative effect of accounting change	0.72	1.46	0.92	0.73	0.92
Cumulative effect of accounting change				(0.01)	(0.03)

Total earnings per common share, diluted	$ 0.72	$ 1.46	$ 0.92	$ 0.72	$ 0.89
Total earnings per common share, basic	$ 0.73	$ 1.48	$ 0.93	$ 0.73	$ 0.90
Dividends paid per common share	$ 0.595	$ 0.57	$ 0.545	$ 0.515	$ 0.49
Book value per common share at year-end	$ 17.27	$ 17.41	$ 15.82	$ 15.50	$ 15.54
Total Assets at Year-End:					
Avista Utilities	$ 3,009,499	$ 2,895,883	$ 2,838,154	$ 2,608,155	$ 2,532,936
Energy Marketing and Resource Management	30,690	1,017,203	2,012,354	1,002,843	1,013,213
Advantage IQ	108,929	100,431	46,094	47,318	45,621
Other	40,679	42,991	51,892	53,305	48,305
Total	$ 3,189,797	$ 4,056,508	$ 4,948,494	$ 3,711,621	$ 3,640,075
Long-Term Debt (including current portion)	$ 948,833	$ 976,459	$ 1,029,514	$ 986,988	$ 954,723
Long-Term Debt to Affiliated Trusts	113,403	113,403	113,403	113,403	113,403
Preferred Stock Subject to Mandatory Redemption (1)		26,250	28,000	29,750	31,500
Stockholders Equity	$ 913,966	$ 914,525	$ 768,849	$ 751,106	$ 751,252
Ratio of Earnings to Fixed Charges (2)	1.71	2.17	1.74	1.60	1.88
Ratio of Earnings to Fixed Charges and Preferred Dividend Requirements (2)	1.71	2.17	1.74	1.60	1.85

(1) Preferred Stock Subject to Mandatory Redemption 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) See Exhibit 12 for computations.

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Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations
Forward-Looking Statements

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

- financial performance,
- capital expenditures,
- dividends,
- capital structure,
- other financial items,
- strategic goals and objectives, and
- plans for operations.

These statements have underlying assumptions (many of which are based, in turn, upon further assumptions). Such statements are made both in our reports filed under the Securities Exchange Act of 1934, as amended (including this Annual Report on Form 10-K), and elsewhere. Forward-looking statements are all statements except those of historical fact including, without limitation, those that are identified by the use of words that include will, may, could, should, intends, plans, seeks, anticipates, estimates, expects, forecasts, projects, p expressions.

Forward-looking statements (including those made in this Annual Report on Form 10-K) are subject to a variety of risks and uncertainties and other factors. Most of these factors are beyond our control and many of them could have a significant effect on our operations, results of operations, financial condition or cash flows. This could cause actual results to differ materially from those anticipated in our statements. Such risks, uncertainties and other factors include, among others:

- weather conditions and its effect on energy demand and generation, including the effect of precipitation and temperatures on the availability of hydroelectric resources and the effect of temperatures on customer demand;
- changes in wholesale energy prices that can affect, among other things, cash needed to purchase electricity, natural gas for our retail customers and natural gas fuel for electric generation, and the value of surplus energy sold, as well as the market value of derivative assets and liabilities;

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

the effect of state and federal regulatory decisions affecting our ability to recover costs and/or earn a reasonable return including, but not limited to, the disallowance of costs that we have deferred;

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

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

the outcome of legal proceedings and other contingencies;

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

wholesale and retail competition including, but not limited to, electric retail wheeling and transmission costs;

the ability to relicense and maintain licenses for our hydroelectric generating facilities at cost-effective levels with reasonable terms and conditions;

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

unanticipated delays or changes in construction costs, as well as our ability to obtain required operating permits for present or prospective facilities;

natural disasters that can disrupt energy production or delivery, as well as the availability and costs of materials and supplies and support services;

blackouts or disruptions of interconnected transmission systems;

the potential for future terrorist attacks or other malicious acts, particularly with respect to our utility assets;

changes in the long-term climate of the Pacific Northwest, which can affect, among other things, customer demand patterns and the volume and timing of streamflows to our hydroelectric resources;

changes in future economic conditions in our service territory and the United States in general, including inflation or deflation;

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- changes in industrial, commercial and residential growth and demographic patterns in our service territory;
- the loss of significant customers and/or suppliers;
- default or nonperformance on the part of any parties from which we purchase and/or sell capacity or energy;
- deterioration in the creditworthiness of our customers and counterparties;
- our ability to obtain financing through the issuance of debt and/or equity securities, which can be affected by various factors including our credit ratings, interest rates and other capital market conditions;
- the effect of any change in our credit ratings;
- changes in actuarial assumptions, the interest rate environment and the actual return on plan assets for our pension plan, which can affect future funding obligations, costs and pension plan liabilities;
- increasing health care costs and the resulting effect on health insurance provided to our employees and retirees;
- increasing costs of insurance, changes in coverage terms and our ability to obtain insurance;
- employee issues, including changes in collective bargaining unit agreements, strikes, work stoppages or the loss of key executives, as well as our ability to recruit and retain employees;
- the potential effects of negative publicity regarding business practices, whether true or not, which could result in, among other things, costly litigation and a decline in our common stock price;
- changes in technologies, possibly making some of the current technology obsolete;
- changes in tax rates and/or policies; and
- changes in our strategic business plans, which may be affected by any or all of the foregoing, including the entry into new businesses and/or the exit from existing businesses.

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

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

Restatement of 2006 and 2005 Financial Statements

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

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

Potential Holding Company Formation

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

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Business Segments

We have three reportable business segments as follows:

Avista Utilities generation, transmission and distribution of electric energy and distribution of natural gas to retail customers, as well as wholesale purchases and sales of energy commodities. Avista Utilities is an operating division of Avista Corp. comprising our regulated utility operations.

Energy Marketing and Resource Management electricity and natural gas marketing, trading and resource management. The activities of this business segment were conducted primarily by Avista Energy, Inc. (Avista Energy), an indirect subsidiary of Avista Corp. On June 30, 2007, Avista Energy and Avista Energy Canada, Ltd. (Avista Energy Canada) completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy. Completion of this transaction effectively ends the majority of the operations of this business segment. This segment still owns natural gas storage facilities and has operating revenues and resource costs related to the power purchase agreement for a 270 megawatt (MW) natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant). The Lancaster Plant is owned by an unrelated third-party and all of the output from the plant is contracted to Avista Energy through 2026. The majority of the rights and obligations of the power purchase agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, we expect these rights and obligations will be transferred to Avista Utilities, subject to future regulatory approval.

Advantage IQ facility information and cost management services for multi-site customers. The activities of this business segment are conducted by Advantage IQ, Inc. (Advantage IQ), an indirect subsidiary of Avista Corp.

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

Avista Energy, Advantage IQ and the various other companies are subsidiaries of Avista Capital, Inc. (Avista Capital), which is a direct, wholly owned subsidiary of Avista Corp. Our total common stockholders equity was $914.0 million as of December 31, 2007, of which $71.4 million represented our investment in Avista Capital. Our investment in Avista Capital decreased significantly in 2007 primarily due to the sale of substantially all of Avista Energy s contracts and ongoing operations and the subsequent dividends to Avista Corp. through Avista Capital.

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

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

Executive Level Summary

Overall

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

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

2007 was a year of repositioning our company with a focus on the future of our utility operations. Moody s Investors Service and Standard & Poor s recently upgraded our credit ratings, which resulted in an investment grade rating for our senior unsecured debt and corporate rating from each of these rating agencies. The upgrade reflects several steps taken over the past few years to lower our business risk profile and improve financial metrics. The most recent significant steps were the sale of substantially all of Avista Energy s contracts and ongoing operations and our general rate case settlement in Washington.

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

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

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

Avista Utilities

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

- weather conditions,
- the price of natural gas in the wholesale market, including the effect on the price of fuel for generation,
- the price of electricity in the wholesale market, including the effects of weather conditions, natural gas prices and other factors affecting supply and demand, and
- regulatory decisions, allowing our utility to recover costs, including purchased power and fuel costs, on a timely basis, and to earn a fair return on investment.

Weather has a significant effect on our utility operations. Weather can impact customer demand and operating revenues and we normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce operating revenues. In addition, below normal precipitation (particularly winter snowpack) and other streamflow conditions can negatively impact electric resource costs by decreasing hydroelectric generation capability and increasing our reliance on market purchases and thermal generation. Regional precipitation and snowpack conditions typically have a significant effect on the wholesale price of electricity. In addition, high demand for electricity will generally increase both the quantity needed and price of fuel for electric generation and wholesale electric market prices.

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

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

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

Our utility net income was $43.8 million for 2007, a decrease from $57.8 million for 2006 primarily due to a decrease in gross margin (operating revenues less resource costs). The decrease was also due to the disallowance of

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unamortized debt repurchase costs in the Washington general rate case settlement, an increase in other operating expenses and an increase in depreciation and amortization. This was partially offset by a decrease in interest expense. The decrease in gross margin was primarily due to the difference in electric resource costs as compared to the amount included in base retail rates. We recognized an expense of $8.5 million under the Energy Recovery Mechanism (ERM) in Washington for 2007 compared to a benefit of $2.6 million under the ERM for 2006. The increase in electric resource costs for 2007 (as compared to the amount included in base rates) was primarily due to lower hydroelectric generation, higher purchased power and fuel costs and greater use of our thermal generating resources (particularly Coyote Springs 2).

We plan to continue to invest in generation, transmission and distribution systems with a focus on providing reliable service to our customers. Utility capital expenditures were $205.8 million for 2007. We expect utility capital expenditures to be $200 million for 2008.

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

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

- Implementation of the general rate increase in Washington effective January 1, 2008, which includes resetting the base level of power supply costs used in the ERM calculations. Given the forecasted improvement in hydroelectric generation and the resetting of the base level of power supply costs used in the ERM calculations, we project a benefit under the ERM in 2008.

- The write-down of a turbine and the disallowance of debt repurchase costs in 2007. These charges should not recur in 2008.

- A decrease in interest expense due to the maturity of $273 million of 9.75 percent Senior Notes on June 1, 2008. We will issue new debt to fund a significant portion of the maturing debt and it should be at a substantially lower rate. In 2004, we entered into forward-starting interest rate swap agreements effectively locking in market fixed interest rates, which were relatively low compared to historical interest rates, for $125 million of our forecasted debt issuances in 2008.

- We expect slightly above normal hydroelectric generation and an increase in electric and natural gas retail loads in 2008.

Energy Marketing and Resource Management (Avista Energy)

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

The historical activities of Avista Energy included:

- trading electricity and natural gas,

- the optimization of generation assets owned by other entities,

- long-term electric supply contracts,
- natural gas storage, and
- electric transmission and natural gas transportation arrangements.

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

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

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

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

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

Advantage IQ

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

Other Businesses

Over time as opportunities arise, we plan to dispose of assets and phase out operations that do not fit with our overall corporate strategy. However, we may invest incremental funds to protect our existing investments and invest in new businesses that fit with our overall corporate strategy. The net loss for these operations was $0.1 million for 2007 compared to a net loss of $2.7 million for 2006. This improvement in results on a year-to-date basis was partially due to net gains on certain long-term venture fund investments in 2007 as compared to net losses in 2006, as well as income tax adjustments recorded in 2006.

Liquidity and Capital Resources

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

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

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

Excluding long-term debt obligations in 2008, we expect net cash flows from operating activities and our $320.0 million committed line of credit to provide adequate resources to fund:

capital expenditures,

dividends, and

other contractual commitments.

In December 2006, we entered into a sales agency agreement with a sales agent to issue up to 2 million shares of our common stock from time to time. During the second half of 2008, we plan to begin issuing common stock under this sales agency agreement.

Avista Utilities Electric Resources

As of December 31, 2007, our generation facilities had a total net capability of 1,771 MW, of which 55 percent was hydroelectric and 45 percent was thermal. In addition to company owned generation resources, we have a number of long-term power purchase and exchange contracts that increase our available resources. See Note 6 of the Notes to Consolidated Financial Statements for information with respect to the resource optimization process.

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Avista Utilities Regulatory Matters

General Rate Cases

In recent years (particularly in 2007), we have generally not earned our authorized rates of return in our regulated utility operations. We regularly review the need for electric and natural gas rate changes in each state in which we provide service. We will continue to file for rate adjustments to:

- provide for recovery of operating costs and capital investments, and
- more closely align earned returns with those allowed by regulators.

With regards to the timing and plans for future filings, the assessment of our need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include in-service dates of major infrastructure investments and the timing of changes in major revenue and expense items. We are planning to file general rate cases in both Washington and Idaho in 2008.

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

Jurisdiction and service	Implementation Date	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Washington electric and natural gas	January 2008	8.20%	10.2%	46%
Idaho electric and natural gas	September 2004	9.25%	10.4%	43%
Oregon natural gas	April 2008 (1)	8.21%	10.0%	50%

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

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

In October 2007, we reached an all-party settlement that resolved all issues in our Washington general rate case. The settlement was approved by the WUTC in December 2007. As agreed to in the settlement, on January 1, 2008, electric rates for our Washington customers increased by an average of 9.4 percent, which is designed to increase annual revenues by $30.2 million. As part of this general rate increase, the base level of power supply costs used in the Energy Recovery Mechanism (ERM) calculations was updated. Also, on January 1, 2008, natural gas rates increased by an average of 1.7 percent, which is designed to increase annual revenues by $3.3 million. Approximately one-half of the increase in natural gas rates is related to storage-capacity release revenues recovered from a third party. This is a transfer between revenue classes and has no impact on net income. The settlement is based on a rate of return of 8.2 percent with a common equity ratio of 46 percent and a 10.2 percent return on equity. Our original request was based on a rate of return of 9.39 percent with a common equity ratio of 47.8 percent and an 11.3 percent return on equity.

In addition, we agreed to write off $3.8 million of unamortized debt repurchase costs in 2007. These costs were for premiums paid to repurchase higher coupon debt prior to its scheduled maturity as part of an effort to reduce interest expense.

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

As part of the general rate case settlement agreement that was modified and approved by the WUTC in December 2005, we agreed to increase the utility equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008. If we do not meet those targets, it could result in a reduction to base rates of 2 percent for each target. The

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calculation of the utility equity component is essentially the ratio of our total consolidated common equity to total capitalization excluding, in each case, our investment in Avista Capital. The utility equity component was approximately 45 percent as of December 31, 2007.

Oregon Senate Bill 408

The OPUC issued amended rules in September 2007 related to Oregon Senate Bill 408 (OSB 408). OSB 408 was enacted into law in 2005. These rules direct the utility to establish an automatic adjustment clause to account for the difference between income taxes collected in rates and taxes paid to units of government, net of adjustments, when that difference exceeds $100,000. The automatic adjustment clause may result in either rate increases or rate decreases and applies only to taxes paid and collected on or after January 1, 2006.

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

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

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

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

Natural Gas Decoupling

In February 2007, the WUTC approved the implementation of a natural gas decoupling mechanism. Decoupling separates the direct link between natural gas sales volume and the recovery of the fixed cost of providing service to our customers. Because our rate structure provides for recovery of the majority of fixed costs on a per-therm (sales volume) basis, energy efficiency and conservation objectives have been directly at odds with the recovery of fixed costs, which do not vary with the volume of natural gas sold. Our decoupling mechanism should allow us to recover lost margin resulting from lower usage by Washington customers due to conservation and price elasticity. However, the mechanism does not provide rate adjustments related to abnormal weather. The decoupling mechanism is a three-year pilot that began in January 2007. A rate adjustment in any one year would be limited to no more than 2 percent. Our first decoupling rate adjustment became effective November 1, 2007. The rate adjustment is designed to recover $0.3 million over a twelve-month period or a 0.2 percent increase for residential and commercial customers, representing 80 percent of the lost margin for the period January through June 2007.

Accounting for Debt Repurchase Costs

The WUTC staff raised questions and requested information regarding our method of amortization of costs related to debt repurchased between 2002 and 2006. After discussions with the WUTC staff, we agree that the costs associated with debt repurchases beginning in 2002 should have been accounted for in accordance with Federal Energy Regulatory Commission (FERC) General Instruction 17 (FERC 17). In May 2007, the

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

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Power Cost Deferrals and Recovery Mechanisms

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

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

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

The initial amount of power supply costs in excess or below the level in retail rates, which we either incur the cost of, or receive the benefit from, is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. We incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. We will share annual power supply cost variances between $4.0 million and $10.0 million with customers. As such, 50 percent of the annual power supply cost variance in this range is deferred for future surcharge or rebate to customers and we incur the cost of, or receive the benefit from, the remaining 50 percent. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, 90 percent of the cost variance is deferred for future surcharge or rebate. We incur the cost of, or receive the benefit from, the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates. The following is a summary of the ERM:

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

Under the ERM, we make an annual filing on or before April 1st of each year to provide the opportunity for the WUTC staff and other interested parties to review the prudence of and audit the ERM deferred power cost transactions for the prior calendar year. The ERM provides for a 90-day review period for the filing; however, the period may be extended by agreement of the parties or by WUTC order.

We have a Power Cost Adjustment (PCA) mechanism in Idaho that allows us to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, we defer 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for our Idaho customers. In June 2007, the IPUC approved continuation of the PCA mechanism with the annual rate adjustment provision. The October 1 rate adjustments recover or rebate power costs deferred during the preceding, July-June, twelve-month period. The PCA rate surcharge, as approved by the IPUC, increased from 2.5 percent to 4.7 percent on October 1, 2007.

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

	Washington	Idaho	Total
Deferred power costs as of December 31, 2005	$ 96,191	$ 7,987	$ 104,178
Activity from January 1 December 31, 2006:			
Power costs deferred		5,718	5,718
Interest and other net additions	4,291	300	4,591
Recovery of deferred power costs through retail rates	(30,323)	(4,648)	(34,971)
Deferred power costs as of December 31, 2006	70,159	9,357	79,516
Activity from January 1 December 31, 2007:			
Power costs deferred	16,344	16,750	33,094
Interest and other net additions	3,023	788	3,811
Recovery of deferred power costs through retail rates	(31,002)	(5,732)	(36,734)
Deferred power costs as of December 31, 2007	$ 58,524	$ 21,163	$ 79,687

Purchased Gas Adjustments

Effective November 1, 2007, natural gas rates decreased:

6.0 percent in Washington,

4.6 percent in Idaho, and

1.7 percent in Oregon.

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

Results of Operations

The following provides an overview of changes in our Consolidated Statements of Income. More detailed explanations are provided, particularly for operating revenues and operating expenses in the business segment discussions (Avista Utilities, Energy Marketing and Resource Management, Advantage IQ and the other businesses) that follow this section.

2007 compared to 2006

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

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

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

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

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

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

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

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

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

a decrease of $4.5 million in the Energy Marketing and Resource Management segment due to the sale of Avista Energy s ongoing operations, partially offset by the loss on the sale,

an increase of $6.8 million for Advantage IQ due to expanding operations and consulting services, and

a decrease of $1.0 million in the other businesses due to lower operating expenses at AM&D and the accrual of an environmental liability at Avista Development during 2006.

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

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

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

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

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

2006 compared to 2005

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

- natural gas revenues of $82.3 million primarily due to the increased volume of wholesale natural gas sales and an increase in retail natural gas rates, and

- electric revenues of $24.3 million reflecting increased retail revenues and sales of fuel, partially offset by decreased wholesale revenues.

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

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

- Advantage IQ of $7.9 million primarily due to customer growth as well as an increase in interest earnings on funds held for customers, and

- the other businesses of $2.7 million primarily due to increased sales at AM&D.

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

- natural gas resource costs of $79.0 million reflecting an increase in the volume of purchases, as well as the amortization of deferred natural gas costs (due to recovery from customers), and

- electric resource costs of $3.0 million reflecting an increase in base resource costs as set forth in the Washington general rate case implemented on January 1, 2006, as well as an increase in fuel for generation and other fuel costs (representing the economic sale of fuel that was not used in generation).

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

- stock and performance based compensation of $2.1 million,

- distribution maintenance costs of $2.1 million, and

- electric sales and service costs of $1.1 million.

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

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

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

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

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

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

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

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

Avista Utilities

2007 compared to 2006

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

- other utility operating expenses (primarily due to the impairment of a turbine, increased maintenance expenses, natural gas distribution expenses, outside services, and regulatory commission fees).
- depreciation and amortization (due to additions to utility plant), and
- taxes other than income taxes (primarily due to increased retail electric and natural gas revenues and related taxes).

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

	Electric	Natural Gas	Total

	2007	2006	2007	2006	2007	2006
Operating revenues	$ 711,130	$ 747,383	$ 577,233	$ 520,555	$ 1,288,363	$ 1,267,938
Resource costs	322,237	346,980	458,761	404,666	780,998	751,646
Gross margin	$ 388,893	$ 400,403	$ 118,472	$ 115,889	$ 507,365	$ 516,292

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

The following table presents our utility electric operating revenues and megawatt-hour (MWh) sales for the year ended December 31 (dollars and MWhs in thousands):

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

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

- total MWhs sold (increased revenues $8.8 million) primarily due to customer growth and partially due to an increase in use per customer, and

- revenue per MWh (increased revenues $13.3 million) primarily due to the elimination of the BPA residential exchange credit.

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

Wholesale electric revenues decreased $20.5 million due to:

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

- an increase in sales prices (increased revenues $14.2 million).

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market as sales of fuel. Sales of fuel decreased $35.3 million as a greater percentage of our fuel purchases were used in generation.

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

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

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

Natural gas revenues increased $56.7 million due to an increase in retail and wholesale natural gas revenues. The $8.2 million increase in retail natural gas revenues was due to higher retail rates (increased revenues $4.0 million) and increased volumes (increased revenues $4.2 million).

We sold more retail natural gas in 2007 primarily due to customer growth. The increase in our wholesale revenues of $48.9 million was due to an increase in volumes (increased revenues $43.4 million) and an increase in prices (increased revenues $5.5 million). Wholesale sales reflect the balancing of loads and resources and the sale of resources in excess of load requirements as part of the natural gas procurement process. Any variance between the revenues and costs of the sale of resources in excess of load requirements is accounted for through the PGA mechanisms.

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

	Electric Customers		**Natural Gas Customers**	
	2007	**2006**	**2007**	**2006**
Residential	306,737	300,940	273,415	267,345
Commercial	38,488	37,912	32,327	31,746
Interruptible			41	41
Industrial	1,378	1,388	261	254
Public street and highway lighting	426	425		
Total retail customers	347,029	340,665	306,044	299,386

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

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

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

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

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

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

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

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

2006 compared to 2005

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

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

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

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

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

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

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

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

The following table presents our utility electric operating revenues and megawatt-hour (MWh) sales for the year ended December 31 (dollars and MWhs in thousands):

	Electric Operating Revenues		Electric Energy MWh sales	
	2006	2005	2006	2005
Residential	$ 234,714	$ 211,934	3,578	3,420
Commercial	221,193	203,480	3,110	2,994
Industrial	92,961	91,552	2,062	2,091
Public street and highway lighting	5,268	4,898	25	25
Total retail	554,136	511,864	8,775	8,530
Wholesale	126,208	151,429	2,117	2,508
Sales of fuel	48,176	41,831		

Other	18,863	17,988		
Total	$ 747,383	$ 723,112	10,892	11,038

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

revenue per MWh (increased revenues $26.8 million) primarily due to the Washington general rate increase of 7.5 percent as well as a 1.0 percent increase in the ERM surcharge, both of which were implemented on January 1, 2006, and

total MWhs sold (increased revenues $15.5 million) primarily due to customer growth and partially due to an increase in use per customer (due to warmer weather during the summer cooling season, partially offset by warmer weather during the winter heating season).

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

volumes (decreased revenues $23.3 million) consistent with decreased wholesale purchases and decreased resource optimization activities, and

prices (decreased revenues $1.9 million).

When electric wholesale market prices are below the cost of operating our natural gas-fired thermal generating units, we sell the natural gas purchased for generation in the wholesale market as sales of fuel. Sales of fuel increased $6.3 million as a greater percentage of our fuel purchases were not used in generation (during the first quarter of 2006).

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

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

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

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

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

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

	2006	**2005**
Electric resource costs:		
Power purchased	$ 150,719	$ 186,703
Power cost amortizations, net of deferrals	29,259	24,209
Fuel for generation	109,723	93,034

Other fuel costs	50,881	36,636
Other regulatory amortizations, net	(6,199)	(6,532)
Other electric resource costs	12,597	9,895
Total electric resource costs	346,980	343,945
Natural gas resource costs:		
Natural gas purchased	371,142	335,796
Natural gas amortizations (deferrals), net	28,426	(13,912)
Other regulatory amortizations, net	5,098	3,767
Total natural gas resource costs	404,666	325,651
Total resource costs	$ 751,646	$ 669,596

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

- price of power purchases (decreased costs $17.9 million) due to overall decreases in wholesale markets, and

- volume of power purchases (decreased costs $18.1 million) primarily due to increased hydro generation.

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

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

Other fuel costs increased $14.2 million. This represents fuel that was purchased for generation, but was later sold when conditions indicated that it was not economic to use the fuel in generation as part of the resource optimization process. The associated revenues are reflected as sales of fuel. Other fuel costs exceeded revenues we received from selling the natural gas. We account for this shortfall under the ERM in Washington and the PCA in Idaho. The increase in other fuel costs was primarily due to a reduced percentage of fuel used in generation and higher natural gas fuel prices.

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

Energy Marketing and Resource Management

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

The historical activities of Avista Energy included:

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

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

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

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

Overall segment results for 2007 compared to 2006

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

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

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

Overall segment results for 2006 compared to 2005

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

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

Operating revenues decreased $116.0 million to $61.5 million primarily due to a decrease of $60.3 million in net trading margin on contracts accounted for under SFAS No. 133 and a $63.2 million decrease from sales of natural gas to commercial and industrial end-user customers (both through Avista Energy Canada and to Montana customers). This category of revenues decreased significantly in 2007 with the sale of substantially all of Avista Energy s contracts and ongoing operations on June 30, 2007.

Resource costs decreased $75.5 million primarily due to decreased resource costs related to sales of natural gas to commercial and industrial end-user customers, and a change in natural gas inventory. This category of expenses decreased significantly in 2007 with the sale of substantially all of Avista Energy s contracts and ongoing operations on June 30, 2007.

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

The remaining operating revenues and resource costs for this segment primarily represent payments for the power purchase agreement for the Lancaster Plant. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010 through 2026, the rights and obligations of the power purchase agreement for the Lancaster Plant will be contracted to Avista Energy. We expect that these rights and obligations will be transferred to our regulated utility, subject to future approval by the WUTC and the IPUC.

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

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

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

- $3.9 million from sales of natural gas to commercial and industrial end-user customers (a decrease through Avista Energy Canada offset by an increase in revenues from Montana customers), and

- $19.4 million under the Agency Agreement with Avista Utilities as natural gas procurement operations were transitioned to Avista Utilities effective April 1, 2005.

Resource costs decreased primarily due to decreased resource costs:

- under the Agency Agreement with Avista Utilities,

- related to sales of natural gas to commercial and industrial end-user customers (a decrease through Avista Energy Canada, partially offset by increases for Montana customers), and

- for transportation and transmission costs.

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

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

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

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

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

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

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

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Energy trading activities and positions

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

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

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

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

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

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

Advantage IQ

2007 compared to 2006

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

2006 compared to 2005

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

Other Businesses

2007 compared to 2006

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

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

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2006 compared to 2005

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

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

New Accounting Standards

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109, (FIN 48) which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. We adopted FIN 48 in the first quarter of 2007. The adoption of FIN 48 did not have a cumulative effect on our financial condition and results of operations. See Notes 2 and 12 of the Notes to Consolidated Financial Statements for further information.

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

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option is elected would be reported in net income. We will be required to adopt SFAS No. 159 in 2008. We do not plan to use the fair value option under SFAS No. 159 and as such do not expect SFAS No. 159 to have any impact on our financial condition and results of operations.

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

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements. This statement amends Accounting Research Bulletin No. 51, Consolidated Financial Statements to establish accounting and reporting standards from noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. We will be required to adopt SFAS No. 160 in 2009. We are evaluating the impact SFAS No. 160 will have on our financial condition and results of operations.

Critical Accounting Policies and Estimates

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

Avista Utilities Operating Revenues

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

Our estimate of unbilled revenue is based on:

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

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

Regulatory Accounting

We prepare our consolidated financial statements in accordance with the provisions of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation for our regulated utility operations. SFAS No. 71 requires us to reflect the effect of regulatory decisions in our financial statements. SFAS No. 71 requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) be reflected as deferred charges on our Consolidated Balance Sheets and are not reflected in our statement of income until the period during which matching revenues are recognized. We expect to recover our regulatory assets through future rates. Our regulatory assets are subject to review for prudence and recoverability. As such, certain deferred costs may be disallowed by our regulators. If at some point in the future we determine that we no longer meet the criteria for continued application of SFAS No. 71 for all or a portion of our regulated operations, we could be:

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

Utility Energy Commodity Derivative Assets and Liabilities

Our utility enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of our management of loads and resources and certain contracts are considered derivative instruments. In conjunction with the issuance of SFAS No. 133, the WUTC and the IPUC issued accounting orders authorizing us to offset any derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. As such, we do not recognize unrealized gains or losses on utility derivative commodity instruments in our Consolidated Statements of Income. We recognize realized gains or losses in the period of settlement, subject to regulatory approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM and the PCA mechanism. We use quoted market prices and forward price curves to estimate the fair value of our utility derivative commodity instruments. As such, the fair value of utility derivative commodity instruments recorded on our Consolidated Balance Sheets, are sensitive to market price fluctuations that can occur on a daily basis.

Pension Plans and Other Postretirement Benefit Plans

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

Our Finance Committee of the Board of Directors:

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

We have contracted with an investment consultant who is responsible for managing/monitoring the individual investment managers. The investment managers performance and related individual fund performance is periodically reviewed by the Finance Committee to ensure compliance with our established investment policy objectives and strategies.

Our pension plan assets are invested primarily in marketable debt and equity securities. Pension plan assets may also be invested in real estate, absolute return, venture capital/private equity and commodity funds. In seeking to obtain the desired return to fund the pension plan, the Finance Committee has established investment allocation percentages by asset classes as disclosed in Note 11 of the Notes to Consolidated Financial Statements.

Pension costs (including the Supplemental Executive Retirement Plan (SERP)) were $14.3 million for 2007, $14.5 million for 2006 and $13.4 million for 2005. Of our pension costs, approximately 65 percent are expensed and 35 percent are capitalized consistent with labor charges. Our costs for the pension plan are determined in part by actuarial formulas that are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension costs are affected by:

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

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

- expected return on pension plan assets,

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discount rate used in determining the projected benefit obligation and pension costs, and

assumed rate of increase in employee compensation.

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

In 2006, the form of payment election assumption was analyzed based upon historical trends and future projections. We revised the form of payment election to assume that 5 percent of retirees and 50 percent of vested terminated participants will elect a lump sum payment, based upon the analysis. The form of payment election assumption previously assumed that 50 percent of retirees and vested terminated participants would elect a lump sum payment. The change resulted in an increase of $13.2 million to the pension benefit obligation as of December 31, 2006. The change will also increase future years pension costs.

We have not made any changes to pension plan provisions in 2007, 2006 and 2005 that have had any significant effect on our recorded pension plan amounts. We have revised the key assumption of the discount rate in 2007 and 2006, and the key assumption of the expected long-term return on assets in 2005. Such changes had an effect on our pension costs in 2007, 2006 and 2005 and may affect future years, given the cost recognition approach described above. However, in determining pension obligation and cost amounts, our assumptions can change from period to period, and such changes could result in material changes to our future pension costs and funding requirements.

In selecting a discount rate, we consider yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits. We increased the pension plan discount rate in 2007 to 6.35 percent from 6.15 percent, which was used in 2006 for estimating the benefit obligation.

The assumed long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by our plan. The assumed long-term rate of return was 8.5 percent in each of 2007, 2006 and 2005. The actual return on plan assets, net of fees, was a gain of $18.3 million (or 8.1 percent) for 2007, a gain of $25.2 million (or 12.6 percent) for 2006 and a gain of $11.3 million (or 6.1 percent) for 2005. We periodically analyze the estimated long-term rate of return on assets based upon revisions to the investment portfolio.

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

Actuarial Assumption	Change in Assumption	Effect on Projected Benefit Obligation	Effect on Pension Cost
Expected long-term return on plan assets	-0.5%	$ *	$ 1,130
Expected long-term return on plan assets	+0.5%	*	(1,130)
Discount rate	-0.5%	21,297	2,254
Discount rate	+0.5%	(19,146)	(2,041)

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

We also have a SERP that provides additional pension benefits to our executive officers. The SERP is intended to provide benefits to executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans.

We provide certain health care and life insurance benefits for substantially all of our retired employees. We accrue the estimated cost of postretirement benefit obligations during the years that employees provide service. Assumed health care cost trend rates have a significant effect on the amounts reported for our postretirement plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase our accumulated postretirement benefit obligation as of December 31, 2007 by $1.6 million and the service and interest cost by $0.2 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease our accumulated postretirement benefit obligation as of December 31, 2007 by $1.4 million and the service and interest cost by $0.1 million.

Stock-Based Compensation

We recognize compensation costs relating to share-based payment transactions in our financial statements based on the fair value of the equity or liability instruments issued. We measure (at the grant date) the estimated fair value of performance shares granted in accordance with the provisions of SFAS No. 123R. The fair value of each

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performance share award was estimated on the date of grant using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to a peer group. Expected volatility is based on the historical volatility of our common stock over a three-year period. The expected term of the performance shares is three years based on the performance cycle. The risk-free interest rate is based on the U.S. Treasury yield at the time of grant.

Contingencies

We have unresolved regulatory, legal and tax issues for which there is inherent uncertainty with respect to the ultimate outcome of the respective matter. We account for contingencies in accordance with SFAS No. 5, Accounting for Contingencies, as well as other accounting guidance specific to a particular issue. In accordance with SFAS No. 5, we accrue a loss contingency if it is probable that an asset is impaired or a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. We also disclose losses that do not meet these conditions for accrual, if there is a reasonable possibility that a loss may be incurred.

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

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Liquidity and Capital Resources

Review of Cash Flow Statement

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

Operating Activities Net cash provided by operating activities was $251.6 million for 2007 compared to $201.5 million for 2006. The overall increase was due in part to sale of Avista Energy s contracts and liquidation of Avista Energy s remaining net current assets. Net cash provided by working capital components was $80.9 million for 2007, compared to $16.5 million for 2006. The net cash provided during 2007 primarily reflects positive cash flows from:

- accounts receivable (representing net cash received from our customers primarily related to the liquidation of Avista Energy s receivables), and

- deposits with counterparties (representing the return from counterparties of cash posted as collateral at Avista Energy).

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

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

- accounts receivable (representing net cash received from our customers),

- other current liabilities (primarily due to an increase in customer fund obligations at Advantage IQ), and

- cash deposits from counterparties (representing cash received as collateral funds from our counterparties).

This cash provided was partially offset by a decrease in:

- accounts payable (representing net cash paid to our vendors),

- other current assets (primarily due to an increase in funds held for customers at Advantage IQ), and

- cash deposits with counterparties (representing cash posted as collateral at Avista Energy).

Significant non-cash items included $19.6 million of power and natural gas cost amortizations, net of deferrals, for 2007, a decrease from $56.3 million for 2006 primarily due to an increase in deferrals of power costs as electric resource costs exceeded the amount included in base rates.

Significant changes in non-cash items also included a $26.1 million change in energy commodity assets and liabilities, representing the change to an unrealized loss of $24.6 million on energy trading activities for 2007 as compared to an unrealized gain of $1.5 million for 2006. There was also a decrease in the benefit for deferred income taxes to a benefit of $7.4 million for 2007 from a benefit of $19.2 million for 2006. Income tax payments decreased to $29.4 million for 2007, compared to $63.4 million for 2006.

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

Financing Activities Net cash used in financing activities was $81.5 million for 2007 compared to $59.4 million for 2006. During 2007, our short-term borrowings decreased $4.0 million, which reflects a decrease in the amount of debt outstanding under our $320.0 million committed line of credit. Cash dividends paid increased to $31.5 million (or 59.5 cents per share) for 2007 from $27.9 million (or 57 cents per share) for 2006. Debt maturities were $26.7 million for 2007 and we redeemed the remaining $26.3 million of our preferred stock outstanding as required.

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

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Overall Liquidity

With the completion of the sale of substantially all of Avista Energy s contracts and ongoing operations, our consolidated operating cash flows are primarily derived from the operations of Avista Utilities. The primary source of operating cash flows for our utility operations is revenues (including the recovery of previously deferred power and natural gas costs) from sales of electricity and natural gas. Significant uses of cash flows from our utility operations include the purchase of electricity and natural gas, and payment of other operating expenses, taxes and interest, with any excess being available for other corporate uses such as capital expenditures and dividends. The primary source and use of operating cash flows for Avista Energy was revenues and costs from realized energy commodity transactions as well as cash collateral deposited to or held from counterparties. Significant operating cash outflows for Avista Energy also included other operating expenses and taxes.

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

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

We design operating and capital budgets to control operating costs and optimize capital expenditures, particularly for our regulated utility operations. In addition to operating expenses, we have continuing commitments for capital expenditures for construction, improvement and maintenance of utility facilities.

We will continue to periodically file for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align our earned returns with those allowed by regulators. We filed a general rate case in Washington in April 2007. In October 2007, we reached a settlement in this general rate case that provides for rate increases averaging 9.4 percent for electric and 1.7 percent for natural gas, which was approved by the WUTC in December 2007. This is designed to increase annual electric revenues by $30.2 million and annual natural gas revenues by $3.3 million effective January 1, 2008. In February 2008, we reached a settlement in our Oregon general rate case, which is designed to increase annual revenues by $0.9 million on April 1, 2008 and $1.4 million on November 1, 2008. See further details in the section Avista Utilities - Regulatory Matters.

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

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

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

$85.0 million revolving accounts receivable sales facility, and

$320.0 million committed line of credit.

Our utility has regulatory mechanisms in place that provide for the deferral and recovery of the majority of power and natural gas supply costs. However, if prices increase, deferral balances will increase, which will negatively affect our cash flow and liquidity until such costs, with interest, are recovered from customers.

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Capital Resources

Our consolidated capital structure, including the current portion of long-term debt and short-term borrowings, consisted of the following as of December 31, 2007 and 2006 (dollars in thousands):

	December 31, 2007		December 31, 2006	
	Amount	Percent of total	Amount	Percent of total
Current portion of long-term debt	$ 427,344	21.6%	$ 26,605	1.3%
Short-term borrowings			4,000	0.2
Long-term debt to affiliated trusts	113,403	5.8	113,403	5.6
Long-term debt	521,489	26.4	949,854	46.7
Total debt	1,062,236	53.8	1,093,862	53.8
Preferred stock-cumulative (including current portion)			26,250	1.3
Total liabilities	1,062,236	53.8	1,120,112	55.1
Stockholders equity	913,966	46.2	914,525	44.9
Total	$ 1,976,202	100.0%	$ 2,034,637	100.0%

We need to finance capital expenditures and obtain additional working capital from time to time. The cash requirements needed to service our indebtedness, both short-term and long-term, reduces the amount of cash flow available to fund working capital, purchased power and natural gas costs, capital expenditures, dividends and other requirements. In September 2007, we redeemed the remaining $26.3 million of our outstanding preferred stock. Our stockholders equity decreased $0.6 million during 2007 primarily due to dividends, the liability to subsidiary minority shareholders (Advantage IQ) and other comprehensive loss, mostly offset by net income.

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

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

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

We have a $320.0 million committed line of credit agreement with various banks with an expiration date of April 5, 2011. Under the agreement, we can request the issuance of up to $320.0 million in letters of credit. As of December 31, 2007, we did not have any borrowings outstanding under this committed line of credit, a decrease from $4.0 million as of December 31, 2006. As of December 31, 2007, there were $34.8 million in letters of credit outstanding, a decrease from $77.1 million as of December 31, 2006. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds issued to the agent bank. Such First Mortgage Bonds would only become due and payable in the event, and then only to the extent, that we default on obligations under the committed line of credit.

Our committed line of credit agreement contains customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Utilities for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2007, we were in compliance with this covenant with a ratio of 2.70 to 1. The committed line of credit agreement also has a covenant which does not permit our ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 70 percent at the end of any fiscal quarter. As of December 31, 2007, we were in compliance with this covenant with a ratio of 53.8 percent. If the proposed change in organization to a holding company structure becomes effective, the committed line of credit agreement will remain at Avista Corp. (Avista Utilities). See "Note 26 of the Notes to Consolidated Financial Statements" for further information on the proposed change in organization to a holding company structure.

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Any default on the line of credit or other financing arrangements of Avista Corp. or any of our significant subsidiaries could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. We do not guarantee the indebtedness of any of our subsidiaries. As of December 31, 2007, Avista Corp. and our subsidiaries were in compliance with all of the covenants of our financing agreements.

We are restricted under various agreements and our Restated Articles of Incorporation as to the additional preferred stock we can issue. As of December 31, 2007, we could issue $369.1 million of additional preferred stock at an assumed dividend rate of 6.95 percent.

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

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

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

- deposit of cash

provided, however, that we may not issue any additional First Mortgage Bonds unless our net earnings (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, an on all indebtedness of prior rank. As of December 31, 2007, our property additions and retired bonds would have entitled us to issue $953.3 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2007, the net earnings test would limit the principal amount of additional bonds we could issue to $609.5 million. Thus, the decline in our net earnings (as defined in the Mortgage) in 2007 as compared to 2006 had a negative impact on the principal amount of additional First Mortgage Bonds we can issue. However, we believe that we have adequate capacity to issue First Mortgage Bonds to meet our financing needs over the next several years.

In December 2005, the WUTC issued an order approving the settlement agreement reached in our Washington general rate case with certain conditions. We agreed to increase the utility equity component to 35 percent by the end of 2007 and to 38 percent by the end of 2008. As further discussed at Note 26 of the Notes to the Consolidated Financial Statements, the IPUC accepted a stipulation that we entered with the IPUC Staff that sets forth a variety of conditions related to the proposed implementation of our holding company structure. One of the conditions provides for the same utility equity components that are required in our January 2006 Washington general rate case. If we do not meet those targets, it could result in a reduction in base rates of 2 percent for each target in each of Washington and Idaho. We also entered into a settlement agreement in Washington related to our proposed holding company formation. In this settlement agreement, we committed to increase the utility equity component to 40 percent by June 30, 2008. However, the provision to reduce base rates by 2 percent does not apply if we fail to meet this target. If we fail to meet this Washington equity target at June 30, 2008, we will be required to use our most current actual equity ratio (in lieu of a hypothetical capital structure) in our next Washington general rate filing (subsequent to June 30, 2008). The utility equity component was approximately 45 percent as of December 31, 2007.

In December 2006, we entered into a sales agency agreement with a sales agent to issue up to 2 million shares of our common stock from time to time. During the second half of 2008, we plan to begin issuing common stock under this sales agency agreement.

Inter-Company Debt; Subordination

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

The right of Avista Corp., as a shareholder, to receive assets of any of its direct or indirect subsidiaries upon the subsidiary s liquidation or reorganization (and the consequent right of the holders of debt securities and other creditors

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

Off-Balance Sheet Arrangements

Avista Receivables Corporation (ARC) is our wholly owned, bankruptcy-remote subsidiary formed for the purpose of acquiring or purchasing interests in certain of our accounts receivable, both billed and unbilled. On March 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment was to extend the termination date from March 20, 2007 to March 17, 2008. The Receivables Purchase Agreement was originally entered into on May 29, 2002 and provides us with cost-effective funds for:

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

Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of our receivables. ARC is obligated to pay fees that approximate the purchaser s cost of issuing commercial paper equal in value to the interests in receivables sold. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of our $320.0 million committed line of credit. As of December 31, 2007, we had sold $85.0 million in accounts receivable under this revolving agreement. We expect to renew this facility before the March 17, 2008 expiration.

Spokane Energy, LLC

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

Under this power exchange arrangement, Peaker, LLC (Peaker) purchases capacity from our utility and sells capacity to Spokane Energy LLC (Spokane Energy), our unconsolidated subsidiary formed in 1998 solely for the purpose of facilitating a long-term capacity contract between PGE and Avista Corp. Spokane Energy sells the related capacity to PGE. Peaker acts as an intermediary to fulfill certain regulatory requirements between Spokane Energy and Avista Corp. The transaction is structured such that Spokane Energy bears full recourse risk for a loan (balance of $90.1 million as of December 31, 2007) that matures in January 2015. We have no recourse related to this loan. Peaker makes monthly payments (which are not material to our financial statements) to us for its capacity purchase.

Credit Ratings

The following table summarizes our credit ratings as of February 26, 2008:

	Standard & Poor s (1)	**Moody s (2)**	**Fitch, Inc. (3)**
Avista Corporation			

Corporate/Issuer rating	BBB-	Baa3	BB+
Senior secured debt (4)	BBB+	Baa2	BBB
Senior unsecured debt	BBB-	Baa3	BBB-
Preferred stock	BB	Ba2	BB+
Avista Capital II (5)			
Preferred Trust Securities	BB	Ba1	BB+
AVA Capital Trust III (5)			
Preferred Trust Securities	BB	Ba1	BB+
Rating outlook	Stable	Stable	Positive

(1) Ratings were upgraded in February 2008.

(2) Ratings were upgraded in December 2007.

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

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

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

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

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Pension Plan

As of December 31, 2007, our pension plan had assets with a fair value that was less than the benefit obligation under the plan. We contributed $15 million to the pension plan in both 2006 and 2007. We plan to contribute at least $15 million to the pension plan in 2008. Our total pension plan contributions were $84 million from 2002 through 2007.

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

Dividends

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

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

Our net income available for dividends has generally been derived from our regulated utility operations (Avista Utilities) and Avista Energy.

With the completion of the sale of contracts and the liquidation of Avista Energy s remaining net current assets, almost all of Avista Energy s cash was distributed to Avista Capital through a dividend of $169 million in September 2007. Avista Capital then paid a cash dividend of $155 million to Avista Corp. In December 2007, Avista Capital paid an additional $6 million dividend to Avista Corp. As such, the majority of the proceeds from the Avista Energy transaction were deployed into our regulated utility operations.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock contained in our Restated Articles of Incorporation, as amended, and to long-term debt contained in various indentures. Covenants under the 9.75 percent Senior Notes that mature on June 1, 2008 limit our ability to increase common stock cash dividends to no more than 5 percent over the previous quarter, unless certain conditions are met related to restricted payments. As of December 31, 2007, we met the conditions that would allow us to increase the common stock cash dividend in excess of 5 percent over the previous quarter.

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

As further discussed at Note 26 of the Notes to the Consolidated Financial Statements, the IPUC accepted a stipulation that we entered with the IPUC Staff that sets forth a variety of conditions if and when we implement a holding company structure. One of the conditions would require IPUC approval of any dividend to the holding company that would reduce utility common equity below 25 percent. We entered into a similar agreement in Washington. This agreement would require WUTC approval of any dividend to the holding company that would reduce utility common equity below 30 percent. The utility equity component was approximately 45 percent as of December 31, 2007.

Avista Utilities Operations

Capital expenditures for our utility were $582.4 million for the years 2005 through 2007. We expect utility capital expenditures to be $200 million for 2008, and over $200 million in each of 2009 and 2010. In addition to ongoing needs for our distribution system, significant projects include upgrades to generating facilities. These estimates of capital expenditures are subject to continuing review and adjustment. Actual capital expenditures may vary from our estimates due to factors such as changes in business conditions, construction schedules and environmental requirements. Scheduled long-term debt maturities are $318 million in 2008 and $35 million in 2010. In 2008, we will issue additional long-term debt to a fund a significant portion of these obligations. We locked in the interest rate on $125 million of long-term debt issuances during 2008 through forward-starting interest rate swap agreements.

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

See Notes 5, 14, 15, 16, 17, 20, 21 and 22 of Notes to Consolidated Financial Statements for additional details related to our financing activities.

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

We are close to completing the acquisition of a wind generation site. We expect to construct a 50 MW generation facility in 2010 or 2011 at an estimate cost of approximately $120 million. This amount is not included in our estimates of utility capital expenditures disclosed above. Future generation resource decisions will be impacted by legislation for restrictions on greenhouse gas emissions and renewable energy requirements as discussed at Environmental Issues and Other Contingencies.

Advantage IQ Operations

Capital expenditures for Advantage IQ were $6.1 million for the years 2005 through 2007. We do not expect capital expenditures for the years 2008 through 2010 for Advantage IQ to be significant to our consolidated cash flows and financial condition. However, they are expected to be higher than past years to improve technology that will support continued growth and reliable service to customers. These capital expenditures should be funded by Advantage IQ s cash flows from operations. As of December 31, 2007, Advantage IQ had $0.4 million of debt outstanding related to capital leases.

In 2007, Advantage IQ amended their employee stock incentive plan to provide an annual window at which time holders of common stock can put their shares back to Advantage IQ providing the shares are held for a minimum of six months. Stock is reacquired at fair market value upon the date of reacquisition. This plan was amended to provide liquidity to participants of Advantage IQ s stock option plan. As the repurchase feature is at the discretion of the minority shareholders, a liability of $14.0 million and a deferred income tax asset of $2.6 million were established in 2007 for the intrinsic value of stock options outstanding. An offsetting reduction was made to consolidated retained earnings of $11.4 million.

In February 2008, Advantage IQ entered into a $12.5 million three-year credit agreement with a bank. Advantage IQ has the ability to increase the credit facility to $25 million under the same agreement. The credit agreement is secured by substantially all of Advantage IQ s assets.

Other Operations

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

Contractual Obligations

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

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

Pension plan funding (9)	15	15	15	15	15	
Avista Capital (consolidated):						
Long-term debt						4
Energy purchase contracts (10)	22	22	27	27	27	316
Operating lease obligations (6)	3	3	1			
Total contractual obligations	$ 967	$ 358	$ 347	$ 254	$ 252	$ 3,042

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

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(2) Represents our estimate of interest payments on long-term debt, which is calculated based on the assumption that all debt is outstanding until maturity. Interest on variable rate debt is calculated using the rate in effect at December 31, 2007.

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

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

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

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

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

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

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

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

These contractual obligations do not include income tax payments, including any payments related to uncertain tax positions. The timing of the payments on uncertain tax positions is not reasonably determinable.

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

Competition

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

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

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

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

Participants in the wholesale energy markets include:

- other utilities,
- federal power marketing agencies,
- energy marketing and trading companies,

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- independent power producers,
- financial institutions, and
- commodity brokers.

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

Our subsidiaries in the non-energy businesses, particularly Advantage IQ, are subject to competition for service to existing customers and as they develop products and services and enter new markets. Competition from other companies in these non-energy businesses may mean challenges for a company to be the first to market a new product or service to gain the advantage in market share. Other challenges for these businesses include the availability of funding and resources to meet capital needs, and rapidly advancing technologies which requires continual product enhancement to avoid obsolescence.

Business Risk

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

- streamflow and weather conditions that impact hydroelectric generation, utility operations and customer demand,
- market prices and supply of wholesale energy, which we purchase and sell, including power, fuel and natural gas,
- regulatory disallowance of the recovery of power and natural gas costs, operating costs and capital investments,
- the effects of changes in legislative and governmental regulations, including restrictions on emissions from generating plants and requirements for the acquisition of new resources,
- changes in regulatory requirements,
- availability of generation facilities,
- competition, and
- availability of funding at a reasonable cost.

Also, like other utilities, our facilities and operations are exposed to natural disasters and terrorism risks or other malicious acts. See further reference to risks and uncertainties under Forward-Looking Statements.

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

Our hydroelectric generation was 96 percent of normal in 2007. Our hydroelectric generation was below normal (based on a 70-year average) for six of the past eight years. We cannot determine if lower than normal hydroelectric generation will continue in future years. For 2008, we forecast hydroelectric generation to be slightly above normal. This 2008 forecast will change based upon precipitation, temperatures and other variables during the year. When we have excess hydroelectric generation, its value varies with market prices and other displaceable resources. When hydroelectric generation is below normal, the cost to obtain power from other sources is generally higher. We are not able to predict how the combination of energy resources, energy loads, prices, rate recovery and other factors will ultimately drive deferred power costs and the timing of recovery of our costs in future periods. See further information at Avista Utilities - Regulatory Matters.

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

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

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The FERC continues to conduct proceedings and investigations related to market controls within the western United States that include proposals by certain parties to impose refunds and some of the FERC s decisions have been appealed in Federal Courts. Certain parties have asserted claims for significant refunds from us, which could result in liabilities for refunding revenues recognized in prior periods. We have joined other parties in opposing these proposals. We believe that we have adequate reserves established for refunds that may be ordered. The refund proceedings provide that any refunds would be offset against unpaid energy debts due to the same party. As of December 31, 2007, our accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties. See California Refund Proceeding and Pacific Northwest Refund Proceeding in Note 25 of the Notes to Consolidated Financial Statements for further information with respect to the refund proceedings.

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

Commodity Price Risk

In general, price risk is driven by fluctuation in the market price of the commodity needed, held or traded. The price of energy in wholesale markets is affected primarily by fundamental factors related to production costs and by other factors including weather and the resulting impact on retail loads.

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

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

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

- adequacy of North American production,
- level of imports,

- level of inventories and regional accessibility,
- demand for natural gas, including natural gas as fuel for electric generation,
- the number of market participants and the willingness of market participants to trade,
- global energy markets, including oil or other natural gas substitutes, and
- availability of pipeline capacity to transport natural gas from region to region.

Any combination of these factors that results in a shortage of energy generally causes the market price to move upward. In addition to these factors, wholesale power markets are subject to regulatory constraints including price controls.

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

Credit Risk

Credit risk relates to the losses that we would incur as a result of non-performance of contractual obligations by counterparties to deliver energy or make financial settlements. We often extend credit to counterparties and customers, and we are exposed to the risk of not being able to collect amounts owed to us. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when we establish conservative credit limits. Credit risk includes the risk that a counterparty may default due to circumstances:

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

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Should a counterparty, customer or supplier fail to perform, we may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices.

We seek to mitigate credit risk by:

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

Our credit policies include an evaluation of the financial condition and credit ratings of counterparties, collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. We also use standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty. However, despite mitigation efforts, defaults by our counterparties periodically occur.

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

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

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

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

Credit risk also involves the exposure that counterparties perceive related to our ability to perform deliveries and settlement under physical and financial energy contracts. These counterparties may seek assurances of performance in the form of letters of credit, prepayment, or cash deposits.

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

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

Other Operational and Event Risks

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

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

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

Interest Rate Risk

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by taking advantage of market conditions when timing the issuance of long-term financings and optional debt redemptions and through the use of fixed rate long-term debt with varying maturities. The interest rate on $51.5 million of long-term debt to affiliated trusts is adjusted quarterly, reflecting current market rates. We also have $83.7 million of Pollution Control Bonds with interest rates between 5.0 and 5.13 percent that are subject to remarketing on December 30, 2008. The remarketing of these bonds could result in higher interest rates on these securities. Additionally, amounts borrowed under our $320.0 million committed line of credit have a variable interest rate.

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In 2004, we entered into forward-starting interest rate swap agreements, totaling $125.0 million, to manage the risk that changes in interest rates may affect the amount of future interest payments. These interest rate swap agreements relate to the anticipated issuances of debt to fund maturing debt in 2008. Under the terms of these agreements, the value of the interest rate swaps is determined based upon us paying a fixed rate and receiving a variable rate based on LIBOR. These interest rate swap agreements are considered hedges against fluctuations in future cash flows associated with changes in interest rates in accordance with SFAS No. 133. As of December 31, 2007, we had a derivative liability of $10.5 million and provided cash collateral of $4.1 million to the interest rate swap counterparties related to these interest rate swaps. We estimate that a 10-basis-point increase in forward LIBOR interest rates as of December 31, 2007 would decrease this derivative liability by $1.0 million, while a 10-basis-point decrease would increase the liability by $1.0 million.

Foreign Currency Risk

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

Risk Management

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

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

Our utility measures the monthly, quarterly and annual energy volume of the imbalance between projected power loads and resources. Normal operations result in seasonal mismatches between power loads and available resources. We are able to vary the operation of generating resources to match parts of hourly, daily and weekly load fluctuations. We use the wholesale power markets to sell projected resource surpluses and obtain resources when deficits are projected. Our utility buys and sells fuel for thermal generation facilities based on comparative power market prices and marginal costs of fueling and operating available generating facilities.

Load/resource imbalances within a rolling 18-month planning horizon are compared against established volumetric guidelines and management determines the timing and specific actions to manage the imbalances. We also assess available resource alternatives and actions that are appropriate for longer-term planning periods. Expected load and resource volumes for forward periods are based on monthly and quarterly averages that may vary significantly from the actual loads and resources within any individual month or operating day. Future projections of resources are updated as forecasted streamflows and other factors differ from prior estimates. Forward power markets may be illiquid, and market products available may not match our desired transaction size and shape. Therefore, open imbalance positions exist at any given time.

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

Economic and Utility Load Growth

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

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Based on our forecast for electric customer growth to average 1.8 to 2.0 percent and natural gas customer growth to average 2.7 to 3.0 percent within our service area, we anticipate retail electric and natural gas load growth will average between 2.0 and 3.0 percent annually for the four year period 2008-2011. While the number of electric customers is growing, the average annual usage by each residential electric customer has stabilized. Commercial and industrial customers are expanding square footage and output at existing facilities, so the average customer usage is increasing. Natural gas sales growth has slowed as retail prices have risen 80 percent in the last five years. Population increases and business growth in our three-state service territory remains considerably above the national average. Natural gas loads for space heating vary significantly with annual fluctuations in weather within our service territories.

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

- assumptions relating to weather and economic and competitive conditions,
- internal analysis of company-specific data, such as energy consumption patterns,
- internal business plans, and
- an assumption that we will incur no material loss of retail customers due to self-generation or retail wheeling.

Changes in actual experience can vary significantly from our forward-looking projections.

Succession Planning

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

Environmental Issues and Other Contingencies

We are subject to environmental regulation by federal, state and local authorities. The generation, transmission, distribution, service and storage facilities in which we have an ownership interest are designed and operated in compliance with all applicable environmental laws.

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

Environmental laws and regulations may have the effect of:

- increasing the costs of generating plants,

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

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

Rising concerns about long-term global climate changes could have a significant effect on our business. Changing temperatures and precipitation, including snowpack conditions, affect the availability and timing of hydroelectric generation capacity. Changing temperatures could also increase or decrease customer demand. Our operations could also be affected by changes in laws and regulations intended to mitigate the risk of global climate changes, including restrictions on the operation of our power generation resources.

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

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

In February 2007, the Governors of Arizona, California, New Mexico, Oregon and Washington started the Western Climate Initiative (WCI) for the purpose of developing regional strategies to address climate change. The Governors of Utah and Montana, and the Premiers of British Columbia and Manitoba subsequently joined the WCI. In August 2007, the WCI partners set an overall regional goal for reducing greenhouse gas emissions to 15 percent below 2005 levels by 2020. By August 2008, the WCI partners are expected to complete the design of a market-based mechanism to help achieve this reduction goal.

The greenhouse gas bill passed into law in the state of Washington during 2007 places significant restrictions on greenhouse gas emissions from any new generation plants built in the state of Washington. Furthermore, utilities are prevented from entering into contracts to purchase energy produced by plants in other states that do not meet the same restrictions. Currently, the only type of thermal generating plants that meet these restrictions are combined-cycle natural gas-fired generation turbines. This greenhouse gas bill sets goals to reduce emissions in the state of Washington to 1990 levels by 2020; to 25 percent below 1990 levels by 2035; and to 50 percent below 1990 levels by 2050.

Initiative Measure 937 (I-937) was passed into law through the General Election in Washington in November 2006.

I-937 requires certain investor-owned, cooperative, and government-owned electric utilities (including Avista Corp.) to acquire new renewable energy resources and/or renewable energy credits in incremental amounts until those resources or credits equal 15 percent of the utility s total retail load in 2020. I-937 also requires these utilities to meet biennial energy conservation targets beginning in 2012. Failure to comply with renewable energy and conservation standards will result in penalties of at least $50 per MWh being assessed against a utility for each MWh it is deficient in meeting a standard. A utility would be deemed to comply with the renewable energy standard if it invests at least 4 percent of its total annual retail revenue requirement on the incremental costs of renewable resources and/or renewable credits.

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

In October 2007, we became a member of the Chicago Climate Exchange (CCX), North America s only voluntary, verifiable and legally binding emissions reduction and trading marketplace. The CCX allows participants to earn credits for reducing greenhouse gas emissions and trade the resulting financial instruments at market prices.

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations: Business Risk and Risk Management, Item 7. 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.

Item 8. Financial Statements and Supplementary Data

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

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Avista Corporation

Spokane, Washington

We have audited the accompanying consolidated balance sheets of Avista Corporation and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Avista Corporation and subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 2 to the consolidated financial statements (Note 2), during 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109*. Additionally, as described in Note 2, during 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123(R), *Share-Based Payment* and adopted SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2008 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Seattle, Washington

February 26, 2008

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CONSOLIDATED STATEMENTS OF INCOME

Avista Corporation

For the Years Ended December 31

Dollars in thousands, except per share amounts

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

Total earnings per common share, diluted (Note 23)	$	0.72	$	1.46	$	0.92
Dividends paid per common share	$	0.595	$	0.570	$	0.545

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Avista Corporation

For the Years Ended December 31

Dollars in thousands

	2007	2006 (as restated see Note 31)	2005 (as restated see Note 31)
Net income	$ 38,475	$ 72,941	$ 44,988
Other Comprehensive Income (Loss):			
Foreign currency translation adjustment	1,010	(38)	268
Reclassification adjustment for foreign currency translation adjustment included in loss on sale of contracts	(2,379)		
Unrealized gains (losses) on interest rate swap agreements - net of taxes of $(1,874), $436 and $605, respectively	(3,480)	810	1,123
Reclassification adjustment for realized losses (gains) on interest rate swap agreements deferred as a regulatory (asset) liability - net of taxes of $1,308 and $(1,556)		2,430	(2,889)
Change in unfunded benefit obligation for pension plan - net of taxes of $1,642, $4,023 and $(1,444), respectively	3,050	7,472	(2,681)
Unrealized gains (losses) on derivative commodity instruments - net of taxes of $(324), $(555) and $1,693, respectively	(602)	(1,030)	3,145
Reclassification adjustment for realized gains on derivative commodity instruments included in net income - net of taxes of $(136), $(294) and $(898), respectively	(253)	(546)	(1,668)
Reclassification adjustment for realized losses on derivative commodity instruments included in loss on sale of contracts, net of taxes of $464	862		
Reclassification adjustment for realized losses on investment securities included in net income - net of taxes of $43		80	
Unrealized investment losses - net of taxes of $(9) and $(34)		(16)	(64)
Total other comprehensive income (loss)	(1,792)	9,162	(2,766)
Comprehensive income	$ 36,683	$ 82,103	$ 42,222

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED BALANCE SHEETS

Avista Corporation

As of December 31

Dollars in thousands

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

Total deferred charges	390,113	375,566
Total assets	$ 3,189,797	$ 4,056,508

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED BALANCE SHEETS (continued)

Avista Corporation

As of December 31

Dollars in thousands

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

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Increase (Decrease) in Cash and Cash Equivalents

Avista Corporation

For the Years Ended December 31

Dollars in thousands

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

The Accompanying Notes are an Integral Part of These Statements

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CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Increase (Decrease) in Cash and Cash Equivalents

Avista Corporation

For the Years Ended December 31

Dollars in thousands

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

The Accompanying Notes are an Integral Part of These Statements.

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

Avista Corporation

For the Years Ended December 31

Dollars in thousands

	Common Stock		Note Receivable from Employee Stock Ownership Plan	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
	Shares	Amount				
Balance as of December 31, 2004, as previously reported	48,471,511	$ 618,379	$ (495)	$ (20,533)	$ 155,854	$ 753,205
Cumulative effect of correction of an error (see Note 31)					(2,099)	(2,099)
Balance as of December 31, 2004 (as restated see Note 31)	48,471,511	$ 618,379	$ (495)	$ (20,533)	$ 153,755	$ 751,106
Net income (as restated see Note 31)					44,988	44,988
Equity compensation plan transactions		(5)			(788)	(793)
Issuance of common stock through Dividend Reinvestment Plan	121,628	2,224				2,224
Repayments of note receivable			495			495
Other comprehensive loss				(2,766)		(2,766)
Cash dividends paid (common stock)					(26,443)	(26,443)
Other					38	38
Balance as of December 31, 2005 (as restated see Note 31)	48,593,139	$ 620,598	$	$ (23,299)	$ 171,550	$ 768,849
Net income (as restated see Note 31)					72,941	72,941
Equity compensation expense		3,092				3,092
Issuance of common stock through equity compensation plans	649,061	11,995			(258)	11,737
Issuance of common stock through Employee Investment Plan (401-K)	14,595	324				324
Issuance of common stock through Dividend Reinvestment Plan	95,031	2,137				2,137
Issuance of common stock	3,162,500	77,474				77,474
Other comprehensive income				9,162		9,162
Cumulative effect of accounting change (adoption of SFAS No. 158) (as restated see Note 31)				(3,679)		(3,679)
Cash dividends paid (common stock)					(27,927)	(27,927)
Other					415	415
Balance as of December 31, 2006 (as restated see Note 31)	52,514,326	$ 715,620	$	$ (17,816)	$ 216,721	$ 914,525
Net income					38,475	38,475
Equity compensation expense		2,720				2,720
Issuance of common stock through equity compensation plans	281,224	2,559				2,559

Issuance of common stock through Employee Investment Plan (401-K)	14,685	329					329
Issuance of common stock through Dividend Reinvestment Plan	98,778	2,158					2,158
Common stock issuance costs		(69)					(69)
Other comprehensive loss					(1,792)		(1,792)
Reclassification of preferred stock issuance costs		1,334				(1,334)	
Cash dividends paid (common stock)						(31,451)	(31,451)
Equity transactions of consolidated subsidiaries		2,282					2,282
Liability to subsidiary minority shareholders						(11,377)	(11,377)
Other						(4,393)	(4,393)
Balance as of December 31, 2007	52,909,013	$ 726,933	$	$	(19,608)	$ 206,641	$ 913,966

The Accompanying Notes are an Integral Part of These Statements.

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AVISTA CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of energy as well as other energy-related businesses. Avista Utilities is an operating division of Avista Corp., comprising the regulated utility operations. Avista Utilities generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Utilities has electric generating facilities in western Montana and northern Oregon. Avista Utilities also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeast and southwest Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility business segments including Avista Energy, Inc. (Avista Energy) and Advantage IQ, Inc. (Advantage IQ). Avista Energy was an electricity and natural gas marketing, trading and resource management business. On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations. See Note 3 for further information. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America. See Note 29 for business segment information.

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

- streamflow and weather conditions that impact hydroelectric generation, utility operations and customer demand,
- market prices and supply of wholesale energy, which the Company purchases and sells, including power, fuel and natural gas,
- regulatory disallowance of the recovery of power and natural gas costs, operating costs and capital investments,
- the effects of changes in legislative and governmental regulations, including restrictions on emissions from generating plants and requirements for the acquisition of new resources,
- changes in regulatory requirements,
- availability of generation facilities,
- competition, and
- availability of funding at a reasonable cost.

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

Basis of Reporting

The consolidated financial statements include the assets, liabilities, revenues and expenses of the Company and its subsidiaries, including variable interest entities for which the Company or its subsidiaries are the primary beneficiaries. Intercompany balances were eliminated in consolidation. The accompanying financial statements include the Company s proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 8).

Use of Estimates

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

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

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

AVISTA CORPORATION

System of Accounts

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

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana and Oregon. The Company is also subject to federal regulation by the FERC.

Utility Revenues

Utility revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. Accounts receivable includes unbilled energy revenues of $16.1 million (net of $57.2 million of unbilled receivables sold) as of December 31, 2007 and $21.7 million (net of $51.6 million of unbilled receivables sold) as of December 31, 2006. See Note 5 for information related to the sale of accounts receivable. Revenues and resource costs from Avista Utilities settled energy contracts that are booked out (not physically delivered) are reported on a net basis as part of utility revenues.

Non-Utility Energy Marketing and Trading Revenues

This category of revenues decreased significantly in 2007 with the sale of substantially all of Avista Energy s contracts and ongoing operations on June 30, 2007. The majority of Avista Energy s contracts were accounted for under Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. The net margin on derivative commodity instruments held for trading is reported as non-utility energy marketing and trading revenues. Revenues from contracts that are not derivatives under SFAS No. 133, as well as derivative commodity instruments not held for trading, are reported on a gross basis in non-utility energy marketing and trading revenues. Revenues from Canadian contracts through Avista Energy Canada, Ltd. (Avista Energy Canada), which are not held for trading, are reported on a gross basis in non-utility energy marketing and trading revenues, were $64.5 million in 2007, $119.9 million in 2006 and $144.6 million in 2005.

Other Non-Utility Revenues

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

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company s operating expenses in 2007, 2006 and 2005.

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on net income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense and totaled $51.0 million in 2007, $48.3 million in 2006 and $43.1 million in 2005.

Income Taxes

The Company accounts for income taxes under SFAS No. 109, Accounting for Income Taxes. Under SFAS No. 109, a deferred tax asset or liability is determined based on the enacted tax rates that will be in effect when the differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company s consolidated income tax returns. The deferred tax expense for the period is equal to the net change in the deferred tax asset and liability accounts from the beginning to the end of the period. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax liabilities and regulatory assets are established for tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

AVISTA CORPORATION

Other Income-Net

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

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

Stock-Based Compensation

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

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

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

Accumulated Other Comprehensive Loss

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

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

Earnings Per Common Share

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share is calculated by dividing income available for common stock by diluted weighted average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and contingent stock awards. See Note 23 for earnings per common share calculations.

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AVISTA CORPORATION

Cash and Cash Equivalents

For the purposes of the Consolidated Statements of Cash Flows, the Company considers all temporary investments with a maturity of three months or less when purchased to be cash equivalents. Cash and cash equivalents include cash deposits from counterparties. See Note 7 for further information related to cash deposits from counterparties.

Restricted Cash

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

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

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts. The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

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

Materials and Supplies, Fuel Stock and Natural Gas Stored

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

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

Utility Plant in Service

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

Allowance for Funds Used During Construction

The Allowance for Funds Used During Construction (AFUDC) represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. In accordance with the uniform system of accounts prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant and the debt related portion is credited currently against total interest expense in the Consolidated Statements of Income in the line item capitalized interest. The equity related portion of AFUDC is included in the Consolidated Statement of Income in the line item other income-net. The Company generally is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a fair return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC generally does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was 9.11 percent in 2007 and 2006 and 9.72 percent for 2005. The Company s AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

Depreciation

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

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

- electric thermal production - 28 years,
- hydroelectric production - 77 years,
- electric transmission - 45 years,
- electric distribution - 48 years, and
- natural gas distribution property - 37 years.

The Company recovers certain asset retirement costs through rates charged to customers as a portion of its depreciation expense for which the Company has not recorded asset retirement obligations (see Note 10). The Company had estimated retirement costs included as a regulatory liability on the Consolidated Balance Sheets of $209.4 million as of December 31, 2007 and $197.7 million as of December 31, 2006. These costs do not represent legal or contractual obligations.

Goodwill

Goodwill arising from acquisitions represents the excess of the purchase price over the estimated fair value of net assets acquired. The Company evaluates goodwill for impairment using a discounted cash flow model on at least an annual basis or more frequently if impairment indicators arise. Goodwill is included in other properties and investments-net on the Consolidated Balance Sheets and totaled $5.2 million (Other) as of December 31, 2007 and $6.2 million ($5.2 million in Other and $1.0 million in Energy Marketing and Resource Management) as of December 31, 2006.

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

Regulatory Deferred Charges and Credits

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

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

SFAS No. 71 requires the Company to reflect the impact of regulatory decisions in its financial statements. SFAS No. 71 requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) are reflected as deferred charges or credits on the Consolidated Balance Sheets. These costs and/or obligations are not reflected in the statement of income until the period during which matching revenues are recognized.

If at some point in the future the Company determines that it no longer meets the criteria for continued application of SFAS No. 71 for all or a portion of its regulated operations, the Company could be:

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

The Company s primary regulatory assets include:

- power and natural gas deferrals,
- investment in exchange power,
- regulatory asset for deferred income taxes,
- unamortized debt expense,
- assets offsetting net utility energy commodity derivative liabilities (see Note 6 for further information),
- expenditures for demand side management programs,
- expenditures for conservation programs, and

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- unfunded pensions and other postretirement benefits.

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

Regulatory liabilities include:

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

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

Regulatory assets that are not currently included in rate base, being recovered in current rates or earning a return (accruing interest), totaled $70.6 million as of December 31, 2007, of which the majority related to the regulatory asset for pensions and other postretirement benefits of $51.0 million.

Investment in Exchange Power-Net

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

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt, as well as premiums paid to repurchase debt, which are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. These costs are recovered through retail rates as a component of interest expense. Pursuant to a settlement agreement in its Washington general rate case in 2007, Avista Corp. agreed to write off $3.8 million of unamortized debt repurchase costs. See Note 4 for further details.

Power Cost Deferrals and Recovery Mechanisms

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

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

In Washington, the Energy Recovery Mechanism (ERM) allows Avista Utilities to increase or decrease electric rates periodically with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs and the amount included in base retail rates for Washington customers. Avista Utilities accrues interest on deferred power costs in the Washington jurisdiction at a rate, which is adjusted semi-annually, of 7.8 percent as of December 31, 2007. Total deferred power costs for Washington customers were $58.5 million as of December 31, 2007 and $70.2 million as of December 31, 2006.

The initial amount of power supply costs in excess or below the level in retail rates, which the Company either incurs the cost of, or receives the benefit from, is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. The Company will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. The Company shares annual power supply cost variances between $4.0 million and $10.0 million with its customers. As such, 50 percent of the annual power supply cost variance in this range is deferred for future surcharge or rebate to customers and the Company incurs the cost of, or receives the benefit from, the remaining 50 percent. To the extent that the annual power supply cost variance from the amount included in base

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rates exceeds $10.0 million, 90 percent of the cost variance is deferred for future surcharge or rebate. The Company incurs the cost of, or receives the benefit from, the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates.

The following is a summary of the ERM:

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

Avista Utilities has a power cost adjustment (PCA) mechanism in Idaho that allows it to modify electric rates periodically with Idaho Public Utilities Commission (IPUC) approval. Under the PCA mechanism, Avista Utilities defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. In June 2007, the IPUC approved continuation of the PCA mechanism with the annual rate adjustment provision. The October 1 rate adjustments recover or rebate power costs deferred during the preceding, July-June, twelve-month period. Avista Utilities accrues interest on deferred power costs in the Idaho jurisdiction at a rate, which is adjusted annually, of 5.0 percent as of December 31, 2007. Total deferred power costs for Idaho customers were $21.2 million as of December 31, 2007 and $9.4 million as of December 31, 2006.

Natural Gas Cost Deferrals and Recovery Mechanisms

In the fall of each year, Avista Utilities files a purchased gas cost adjustment (PGA) in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. These annual PGA filings in Washington and Idaho provide for the deferral, and recovery or refund, of 100 percent of the difference between actual and estimated commodity and pipeline transportation costs for the prior year, subject to applicable regulatory review. The annual PGA filing in Oregon provides for deferral, and recovery or refund, of 100 percent of the difference between actual and estimated pipeline transportation costs and commodity costs that are fixed through hedge transactions. Commodity costs that are not hedged for Oregon customers are subject to a sharing mechanism whereby Avista Utilities defers, and recovers or refunds, 90 percent of the difference between these actual and estimated costs. Total net deferred natural gas costs were $2.4 million (an asset of $6.2 million and a liability of $3.8 million) as of December 31, 2007 and $18.3 million as of December 31, 2006.

NOTE 2. NEW ACCOUNTING STANDARDS

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

Effective January 1, 2007, the Company adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109, (FIN 48) which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires the evaluation of a tax position as a two-step process. First, the Company is required to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the more likely than not recognition threshold, it is then measured and recorded at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. The adoption of FIN 48 did not have a cumulative effect on the Company s financial statements. See Note 12 for further information.

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

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

a liability of $60.1 million (associated deferred taxes of $21.0 million) for pensions and other postretirement benefits,

a regulatory asset of $54.2 million (associated deferred taxes of $19.0 million) for pensions and other postretirement benefits,

an increase to accumulated other comprehensive loss of $3.7 million (net of taxes of $2.1 million), and

the removal of the intangible pension asset of $3.7 million (was included in other deferred charges).

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

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option is elected would be reported in net income. The Company will be required to adopt SFAS No. 159 in 2008. The Company does not plan to use the fair value option under SFAS No. 159 and as such does not expect SFAS No. 159 to impact its financial condition and results of operations.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. This statement replaces SFAS No. 141 and addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. This statement requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the transaction at the acquisition date, measured at their fair values as of that date, with limited exceptions. The Company will be required to begin applying this statement to any business combinations in 2009.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements. This statement amends Accounting Research Bulletin No. 51, Consolidated Financial Statements to establish accounting and reporting standards from noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership in the consolidated entity that should be reported as equity in the consolidated financial statements. The Company will be required to adopt SFAS No. 160 in 2009. The Company is evaluating the impact SFAS No. 160 will have on its financial condition and results of operations.

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NOTE 3. DISPOSITION OF AVISTA ENERGY

On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy.

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

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

Proceeds from the transaction included cash consideration for the net assets acquired by Shell Energy and the liquidation of the remaining net current assets of Avista Energy not sold to Shell Energy (primarily receivables, restricted cash and deposits with counterparties). On July 2, 2007, Avista Energy received $34.4 million from Shell Energy based on the value of the net assets sold as of May 31, 2007. This amount was adjusted and Avista Energy paid Shell Energy $4.5 million on August 2, 2007 based on the determination of final market values and other closing adjustments as of June 30, 2007. The pre-tax net loss on the transaction was $4.3 million, which is included in non-utility other operating expenses in the Consolidated Statements of Income for 2007.

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

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

- cash deposits with and from counterparties,
- litigation matters (including matters related to western energy markets), and
- certain employment agreements and employee related obligations.

Certain assets of Avista Energy with a net book value of approximately $30 million have not been liquidated. These primarily include natural gas storage and deferred tax assets. The Company expects that the natural gas storage will ultimately be transferred to Avista Utilities, subject to future regulatory approval. The Company also expects that the power purchase agreement for the Lancaster Plant for the period 2010 through 2026 will be transferred to Avista Utilities, subject to future regulatory approval.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other s affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 25), existing litigation, tax liabilities, matters with respect to storage rights at Jackson Prairie, and any potential issues associated with the power purchase agreement for the Lancaster Plant. In general, such indemnification is not required unless and until a party s claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy s obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. Avista Capital granted Shell Energy a security interest in 50 percent of Avista Capital s common shares of Advantage IQ as collateral for its Guaranty. The aggregate obligations secured by this security interest will in no event exceed $25 million. Avista Capital may substitute collateral, such as cash or letters of credit, in place of the security interest in Advantage IQ s common shares. This security interest in Advantage IQ s common shares will terminate in 18 months (December 31, 2008) except to the extent of claims actually made prior to expiration of the 18-month period. The Guaranty will terminate April 30, 2011 except with respect to claims made prior to termination.

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

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

NOTE 4. IMPAIRMENT OF ASSETS

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

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

NOTE 5. ACCOUNTS RECEIVABLE SALE

Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp. formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. On March 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment extended the termination date from March 20, 2007 to March 17, 2008. Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser s cost of issuing commercial paper equal in value to the interests in receivables sold. On a consolidated basis, the amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp. s $320.0 million committed line of credit (see Note 14). At each of December 31, 2007 and 2006, $85.0 million in accounts receivables were sold under this revolving agreement.

NOTE 6. ENERGY COMMODITY TRADING

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

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

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

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

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economic value. Avista Utilities sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring resources to serve its load obligations. These transactions range from terms of one hour up to multiple years. Avista Utilities makes continuing projections of:

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

On the basis of these projections, Avista Utilities makes purchases and sales of energy to match expected resources to expected electric load requirements. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

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

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

As part of its resource optimization process described above, Avista Utilities manages the impact of fluctuations in electric energy prices by measuring and controlling the volume of energy imbalance between projected loads and resources and through the use of derivative commodity instruments for hedging purposes. Load/resource imbalances within a rolling 18-month planning horizon are compared against established volumetric guidelines and management determines the timing and specific actions to manage the imbalances. Management also assesses available resource decisions and actions that are appropriate for longer-term planning periods.

SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recording of all derivatives as either assets or liabilities on the balance sheet measured at estimated fair value and the recognition of the unrealized gains and losses. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

Avista Utilities enters into forward contracts to purchase or sell electricity and natural gas. Under these forward contracts, Avista Utilities commits to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. Certain of these forward contracts are considered derivative instruments. Avista Utilities also records derivative commodity assets and liabilities for over-the-counter and exchange-traded derivative instruments as well as certain long-term contracts. These contracts are entered into as part of Avista Utilities management of its loads and resources as discussed above. In conjunction with the issuance of SFAS No. 133, the WUTC and the IPUC issued accounting orders authorizing Avista Utilities to offset any derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Consolidated Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM and the PCA mechanism.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as assets or liabilities at market value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives under SFAS No. 133 are generally accounted for at cost until they are settled or realized, unless there is a decline in the fair value of the contract that is determined to be other than temporary.

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