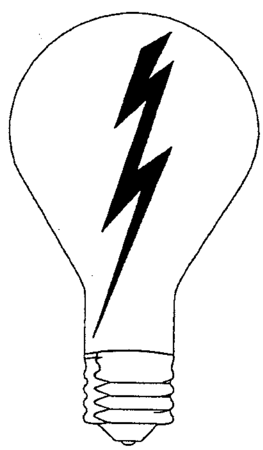
YEAR ENDING December 31, 2007

ANNUAL REPORT
OF

Avista Corporation

ELECTRIC UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

REVISED - 2005

IDENTIFICATION

Year: 2007

1.	Legal Name of Respondent:	Avista Corporation
2.	Name Under Which Respondent Does Business:	Avista Corp. and Avista Utilities
3.	Date Utility Service First Offered in Montana	July, 1960
4.	Address to send Correspondence Concerning Report:	1411 East Mission Avenue PO Box 3727 Spokane, WA 99220
5.	Person Responsible for This Report:	Christy Burmeister-Smith Vice President and Controller
5a.	Telephone Number:	509-495-4256

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:
   1a. Name and address of the controlling organization or person:

   1b. Means by which control was held:

   1c. Percent Ownership:

SCHEDULE 2

Board of Directors

Line No.	Name of Director and Address (City, State) (a)		Remuneration (b)
1	Erik J. Anderson	2420 Carillon Point, Kirkland, WA 98033	$103,333.00
2	Kristianne Blake	P. O. Box 28338, Spokane, WA 99228	$122,666.00
3	Roy Lewis Eiguren	P.O. Box 2720, Boise, ID 83701	$101,333.00
4	Jack W. Gustavel	P.O. Box J, Coeur d'Alene, ID 83816	$102,833.00
5	John F. Kelly	4915 E. Doubletree Ranch Rd., Paradise Valley, AZ	$112,833.00
6	Michael L. Noel	1107 Pine Country Ct., Prescott, AZ 86303	$107,333.00
7	Lura J. Powell, Ph.D.	2400 Stevens Dr., Suite B, Richland, WA 99352	$97,333.00
8	Heidi B. Stanley	111 North Wall Stree, Spokane, WA 99201	$105,833.00
9	R. John Taylor	P. O. Box 538, Lewiston, ID 83501	$114,103.00
10	Gary G. Ely (1)	1411 E. Mission Ave., Spokane, WA 99220	(1)
11	Scott L. Morris (2)	1411 E. Mission Ave., Spokane, WA 99220	(2)
12			
13			
14	(1) Mr. Ely was Chairman of the Board as well as Chief Executive Officer of Avista		
15	Corporation. Mr. Ely retired on December 31, 2007.		
16			
17	(2) Mr. Morris was President and COO of Avista Corporation. Appointed to the Board		
18	in February 2007. Elected Chairman and CEO effective 1/1/2008.		
19			
20			

Officers

Year: 2007

Title of Officer (a)	Department Supervised (b)	Name (c)
Chairman of the Board & Chief Executive Officer (1)	All	Gary G. Ely
President and Chief Operating Officer, President of Avista Utilities (2)	Utility Operations	Scott L. Morris
Executive Vice President & Chief Financial Officer	Finance	Malyn K. Malquist
Senior Vice President, General Counsel and Chief Compliance Officer	Legal	Marian M. Durkin
Senior Vice President of Human Resources & Corporate Sercretary	Human Resources	Karen S. Feltes
Vice President & Controller	Accounting	Christy Burmeister-Smith
Vice President of State & Federal Regulation	Regulatory	Kelly O. Norwood
Vice President of Transmission and Distribution Operations	Transmission and Distribution	Don F. Kopczynski
Vice President, Sustainable Energy Solutions	Utility Operations	Roger D. Woodworth
Vice President of Energy Resources and Optimization	Resource Management	Dennis P. Vermillion
Vice President and Chief Counsel for Regulatory and Governmental Affairs	Legal/Regulatory	David J. Meyer
Vice President of Finance and Treasurer	Finance	Ann M. Wilson
Vice President and Chief Information Officer	Information Technology	James M. Kensok

(1) Retired on December 31, 2007

(2) Appointed Chairman and Chief Executive Officer effective January 1, 2008.

CORPORATE STRUCTURE

Year: 2007

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
2	Avista Capital, Inc.	Parent company to the	($4,595,749)	100.00%
3		Company's subsidiaries.		
5	Avista Capital II	Business trusts formed for the purpose		
6	AVA Captial Trust III	of issuing preferred trust securities.		
8	Advantage IQ, Inc.	Provider of utility bill processing, payment and information		
9		services to multi-site customers in North America.		
11	Avista Energy, Inc.	Wholesale electricity and natural gas trading, marketing and		
12		resource management. Majority of opertions sold 6/30/2007		
14	Avista Energy Canada, Ltd.	A wholly owned subsidiary of Avista Energy that provides natural		
15		gas service to customers in BC, Canada.		
16		Majority of operations sold 6/30/2007.		
18	Avista Power, LLC	Owns non-regulated generation assets.		
20	Avista Turbine Power, LLC	Receives assignments of purchase power agreements.		
22	Avista Rathdrum, LLC	Owned 49 percent of Rathdrum Power LLC (sold 10/2006)		
24	Steam Plant Square LLC	Commercial office and retail leasing.		
25	Courtyard Office Center	Commercial office and retail leasing.		
27	Avista Ventures, Inc.	Invests in emerging businesses.		
29	Avista Development, Inc.	Non-operating company which maintains an investment portfolio		
30		of real estate and other investments.		
32	Pentzer Corporation	Parent of Bay Area Manufacturing and Pentzer Venture Holdings.		
34	Bay Area Manufacturing	Holding Company. Parent of Advanced Manufacturing and		
35		Development, Inc.		
37	Pentzer Venture Holdings	Inactive.		
39	Advanced Manufacturing	Performs custom sheet metal manufacturing of electronic		
40	and Devlopment, Inc.	enclosures. Has a wood products division.		
42	Avista Receivables Corp.	Acquires and sells accounts receivable		
43		of Avista Corp.		
45	Coyote Springs 2, LLC	Developed and owned an electric generation asset.		
47	Spokane Energy, LLC	Marketing of energy.		
49	AVA Formation Corp.	Holding Company. Formed in 2006.		
50	**TOTAL**		(4,595,749)	

CORPORATE ALLOCATIONS

Year: 2007

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1						
2						
3						
4	Not applicable					
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34	**TOTAL**					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2007

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1						
2	None					
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32	**TOTAL**					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1						
2						
3	Avista Energy	Transmission	Market Price	8,192	less than 1%	
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32	**TOTAL**			8,192		

MONTANA UTILITY INCOME STATEMENT

Year: 2007

		Account Number & Title	Last Year	This Year	% Change
1	400	Operating Revenues	14,759,468	14,845,752	0.58%
2					
3		Operating Expenses			
4	401	Operation Expenses	18,907,761	21,031,663	11.23%
5	402	Maintenance Expense	8,095,742	8,216,621	1.49%
6	403	Depreciation Expense	11,333,088	11,412,842	0.70%
7	404-405	Amortization of Electric Plant	none/n.a.	none/n.a.	#VALUE!
8	406	Amort. of Plant Acquisition Adjustments	none/n.a.	none/n.a.	#VALUE!
9	407	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs	none/n.a.	none/n.a.	#VALUE!
11	408.1	Taxes Other Than Income Taxes	7,205,095	7,282,132	1.07%
12	409.1	Income Taxes - Federal	none/n.a.	none/n.a.	#VALUE!
13		- Other	213,789	507,279	137.28%
14	410.1	Provision for Deferred Income Taxes	none/n.a.	none/n.a.	#VALUE!
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	none/n.a.	none/n.a.	#VALUE!
16	411.4	Investment Tax Credit Adjustments	none/n.a.	none/n.a.	#VALUE!
17	411.6	(Less) Gains from Disposition of Utility Plant	none/n.a.	none/n.a.	#VALUE!
18	411.7	Losses from Disposition of Utility Plant	none/n.a.	none/n.a.	#VALUE!
19					
20		**TOTAL Utility Operating Expenses**	45,755,475	48,450,537	5.89%
21		**NET UTILITY OPERATING INCOME**	(30,996,007)	(33,604,785)	-8.42%

MONTANA REVENUES

SCHEDULE 9

		Account Number & Title	Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	7,147	6,818	-4.60%
3	442	Commercial & Industrial - Small	2,223	2,152	-3.19%
4		Commercial & Industrial - Large			
5	444	Public Street & Highway Lighting			
6	445	Other Sales to Public Authorities			
7	446	Sales to Railroads & Railways			
8	448	Interdepartmental Sales	7,445	7,665	2.96%
9					
10		**TOTAL Sales to Ultimate Consumers**	16,815	16,635	-1.07%
11	447	Sales for Resale	14,598,612	14,751,319	1.05%
12					
13		**TOTAL Sales of Electricity**	14,615,427	14,767,954	1.04%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	14,615,427	14,767,954	1.04%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues			
19	451	Miscellaneous Service Revenues			
20	453	Sales of Water & Water Power			
21	454	Rent From Electric Property	45,136	47,639	5.55%
22	455	Interdepartmental Rents			
23	456	Other Electric Revenues	98,905	30,159	-69.51%
24					
25		**TOTAL Other Operating Revenues**	144,041	77,798	-45.99%
26		**Total Electric Operating Revenues**	14,759,468	14,845,752	0.58%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	115,243	141,110	22.45%
6	501 Fuel	14,659,509	16,515,707	12.66%
7	502 Steam Expenses	1,205,731	1,301,489	7.94%
8	503 Steam from Other Sources	16,016		-100.00%
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	11,407	41,533	264.10%
11	506 Miscellaneous Steam Power Expenses	1,357,913	1,606,237	18.29%
12	507 Rents	19,628	29,922	52.45%
13				
14	TOTAL Operation - Steam	17,385,447	19,635,998	12.95%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	354,380	438,221	23.66%
18	511 Maintenance of Structures	454,469	451,048	-0.75%
19	512 Maintenance of Boiler Plant	4,432,308	4,557,363	2.82%
20	513 Maintenance of Electric Plant	444,902	679,784	52.79%
21	514 Maintenance of Miscellaneous Steam Plant	534,244	542,111	1.47%
22				
23	TOTAL Maintenance - Steam	6,220,303	6,668,527	7.21%
24				
25	**TOTAL Steam Power Production Expenses**	23,605,750	26,304,525	11.43%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	Hydraulic Power Generation			
3	Operation			
4	535 Operation Supervision & Engineering	93,170	86,126	-7.56%
5	536 Water for Power			
6	537 Hydraulic Expenses	77,203	71,797	-7.00%
7	538 Electric Expenses	981,051	927,900	-5.42%
8	539 Miscellaneous Hydraulic Power Gen. Expenses	184,514	147,929	-19.83%
9	540 Rents			
10				
11	TOTAL Operation - Hydraulic	1,335,938	1,233,752	-7.65%
12				
13	Maintenance			
14	541 Maintenance Supervision & Engineering	34,077	64,791	90.13%
15	542 Maintenance of Structures	54,805	147,358	168.88%
16	543 Maint. of Reservoirs, Dams & Waterways	33,812	46,805	38.43%
17	544 Maintenance of Electric Plant	1,041,970	810,852	-22.18%
18	545 Maintenance of Miscellaneous Hydro Plant	261,831	39,805	-84.80%
19				
20	TOTAL Maintenance - Hydraulic	1,426,495	1,109,611	-22.21%
21				
22	**TOTAL Hydraulic Power Production Expenses**	2,762,433	2,343,363	-15.17%
23				
24	Other Power Generation			
25	Operation			
26	546 Operation Supervision & Engineering			
27	547 Fuel			
28	548 Generation Expenses			
29	549 Miscellaneous Other Power Gen. Expenses			
30	550 Rents			
31				
32	TOTAL Operation - Other			
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering			
36	552 Maintenance of Structures			
37	553 Maintenance of Generating & Electric Plant			
38	554 Maintenance of Misc. Other Power Gen. Plant			
39				
40	TOTAL Maintenance - Other			
41				
42	**TOTAL Other Power Production Expenses**			
43				
44	Other Power Supply Expenses			
45	555 Purchased Power			
46	556 System Control & Load Dispatching			
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses			
50				
51	**TOTAL Power Production Expenses**	26,368,183	28,647,888	8.65%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

	Account Number & Title		Last Year	This Year	% Change
1		Transmission Expenses			
2	Operation				
3	560	Operation Supervision & Engineering	24,043	23,339	-2.93%
4	561	Load Dispatching	37,335	23,377	-37.39%
5	562	Station Expenses	1,689	2,494	47.66%
6	563	Overhead Line Expenses	57,507	44,435	-22.73%
7	564	Underground Line Expenses			
8	565	Transmission of Electricity by Others			
9	566	Miscellaneous Transmission Expenses			
10	567	Rents	65,802	68,268	3.75%
11					
12		TOTAL Operation - Transmission	186,376	161,913	-13.13%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	29,192	24,151	-17.27%
15	569	Maintenance of Structures	7,523	5,723	-23.93%
16	570	Maintenance of Station Equipment	56,691	59,805	5.49%
17	571	Maintenance of Overhead Lines	345,778	331,248	-4.20%
18	572	Maintenance of Underground Lines			
19	573	Maintenance of Misc. Transmission Plant			
20					
21		TOTAL Maintenance - Transmission	439,184	420,927	-4.16%
22					
23		**TOTAL Transmission Expenses**	625,560	582,840	-6.83%
24					
25		Distribution Expenses			
26	Operation				
27	580	Operation Supervision & Engineering			
28	581	Load Dispatching			
29	582	Station Expenses			
30	583	Overhead Line Expenses			
31	584	Underground Line Expenses			
32	585	Street Lighting & Signal System Expenses			
33	586	Meter Expenses			
34	587	Customer Installations Expenses			
35	588	Miscellaneous Distribution Expenses			
36	589	Rents			
37					
38		TOTAL Operation - Distribution			
39	Maintenance				
40	590	Maintenance Supervision & Engineering			
41	591	Maintenance of Structures			
42	592	Maintenance of Station Equipment			
43	593	Maintenance of Overhead Lines			
44	594	Maintenance of Underground Lines			
45	595	Maintenance of Line Transformers			
46	596	Maintenance of Street Lighting, Signal Systems			
47	597	Maintenance of Meters			
48	598	Maintenance of Miscellaneous Dist. Plant			
49					
50		TOTAL Maintenance - Distribution			
51					
52		**TOTAL Distribution Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision			
4	902 Meter Reading Expenses			
5	903 Customer Records & Collection Expenses			
6	904 Uncollectible Accounts Expenses			
7	905 Miscellaneous Customer Accounts Expenses			
8				
9	TOTAL Customer Accounts Expenses			
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision			
14	908 Customer Assistance Expenses			
15	909 Informational & Instructional Adv. Expenses			
16	910 Miscellaneous Customer Service & Info. Exp.			
17				
18	TOTAL Customer Service & Info Expenses			
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20	Sales Expenses			
21	Operation			
22	911 Supervision			
23	912 Demonstrating & Selling Expenses			
24	913 Advertising Expenses			
25	916 Miscellaneous Sales Expenses			
26				
27	TOTAL Sales Expenses			
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries			
32	921 Office Supplies & Expenses			
33	922 (Less) Administrative Expenses Transferred - Cr.			
34	923 Outside Services Employed			
35	924 Property Insurance			
36	925 Injuries & Damages			
37	926 Employee Pensions & Benefits			
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	228		-100.00%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses			
42	930.2 Miscellaneous General Expenses			
43	931 Rents			
44				
45	TOTAL Operation - Admin. & General	228		-100.00%
46	Maintenance			
47	935 Maintenance of General Plant	9,760	17,556	79.88%
48				
49	**TOTAL Administrative & General Expenses**	9,988	17,556	75.77%
50				
51	**TOTAL Operation & Maintenance Expenses**	27,003,731	29,248,284	8.31%

MONTANA TAXES OTHER THAN INCOME

Year: 2007

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	452	11,105	2356.86%
5	Motor Vehicle Tax	3,545	3,691	4.12%
6	KWH Tax	1,246,923	1,117,650	-10.37%
7	Property Taxes	5,938,718	6,145,973	3.49%
8	Public Commission Tax	10,790	21	-99.81%
9	Colstrip Generation Tax	4,667	3,692	-20.89%
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51	**TOTAL MT Taxes Other Than Income**	7,205,095	7,282,132	1.07%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2007

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	ANDERSON MRAZ DESIGN	Annual report design	77,827		
2	AREVA T & D INC.	Consulting	124,675		
3	ASCENTIUM	Consulting - IT	291,458		
4	AVCO CONSULTING INC	Consulting	154,700		
5	AW REHN AND ASSOCIATES	Employee benefit consulting	326,229		
6	BAIN & COMPANY INC	Consulting	1,666,369		
7	BT COUNTERPANE INTERNET SECURITY INC	Consulting - IT	99,982		
8	CASSO CORPORATION	Consulting	126,315		
9	CERIUM NETWORKS	Consulting - IT	262,218		
10	COATES KOKES	Consulting	84,216		
11	COFFMAN ENGINEERS	Engineering	165,862		
12	CORNERSTONE RESEARCH	Consulting	171,862		
13	DAVID EVANS & ASSOCIATES INC	Engineering	139,803		
14	DAVIS WRIGHT TREMAINE LLP	Legal	1,346,243		
15	DELOITTE & TOUCHE LLP	Auditing	1,218,278		
16	DEWEY BALLANTINE LLP	Legal	586,180		
17	DIVERSIFIED INSPECTIONS	Inspection of equipment	124,682		
18	DORSEY & WHITNEY LLP	Legal	2,023,658		
19	EES CONSULTING	Consulting	93,092		
20	ENSR CORP	Consulting Environmental	216,318		
21	FTI CONSULTING INC	Consulting	138,662		
22	FUJITSU CONSULTING INC	Consulting	496,660		
23	GARLINGTON LOHN & ROBINSON PLLP	Legal	219,509		
24	GARTNER INC	Consulting - IT	173,387		
25	GOLDER ASSOCIATES INC	Consulting Environmental	101,888		
26	H2E INC	Engineering	109,312		
27	HARBOR FISHERIES INC	Consulting fish passage	191,000		
28	HATCH ACRES CORPORATION	Engineering	139,394		
29	HELLER EHRMAN	Legal	773,090		
30	HILLIS CLARK MARTIN & PETERSON	Legal	195,441		
31	IBM	Consulting - IT	164,400		
32	IDAHO DEPT OF FISH & GAME	Bull trout education program	211,804		
33	INTELLITECHTURE	Consulting - IT	193,785		
34	KLEINSCHMIDT ASSOCIATES	Engineering	109,851		
35	KORN FERRY INTERNATIONAL	consulting	105,247		
36	LEVITAN & ASSOCIATES INC	consulting	446,832		
37	NAVIGANT CONSULTING INC	Consulting	95,326		
38	OPEN ACCESS TECHNOLOGY INTL	Consulting - IT	196,259		
39	PACIFIC ECONOMICS GROUP LLC	Consulting	319,204		
40	PAINE HAMBLEN COFFIN BROOKE & MILLER LP	Legal	1,523,874		
41	PARAMETRIX INC	Engineering	152,514		
42	PERVASIVE	Consulting - IT	88,308		
43	POWERTECH LABS INC	Engineering	96,700		
44	REDGRAVE DALEY RAGAN & WAGNER LLP	Legal	205,305		
45	REGULUS INTEGRATED SOLUTIONS LLC	Remittance processing	125,000		
46	RIVER DESIGN GROUP INC	Consulting Environmental	148,427		
47	SOLUTION BEACON LLC	Consulting - IT	529,737		
48	STOEL RIVES LLP	Legal	98,343		
49	TCI OF ALABAMA LLC	Consulting Environmental	76,846		
50	THE ULTIMATE SOFTWARE GROUP INC	Consulting - IT	241,092		
51	TROI IT SOLUTIONS	Consulting - IT	96,658		
52	VAN NESS FELDMAN	Legal	473,468		
53	WASHINGTON GROUP INTL INC	Engineering	96,992		
54	WINSTON & STRAWN LLP	Legal	523,844		
55	**TOTAL Payments for Services**		18,158,125		

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2007

	Description	Total Company	Montana	% Montana
1				
2				
3	Friends of Max Baucus (US Senate)	$2,000.00	$2,000.00	
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19	All contributions in Montana were made by PACs.			
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40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Contributions**	$2,000.00	$2,000.00	

Pension Costs

Year: 2007

1	Plan Name The Retirement Plan for Employees of Avista Corporation.			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Yes	IRS Code: 001		
4	Annual Contribution by Employer: Varies	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	297,018	282,680	-4.83%
8	Service cost	10,210	9,806	-3.96%
9	Interest Cost	18,038	16,086	-10.82%
10	Plan participants' contributions			
11	Amendments			
12	Actuarial Gain	(6,567)	3,089	147.04%
13	Benefits paid	(14,786)	(14,643)	0.97%
14	Expenses paid	(299)		100.00%
15	Benefit obligation at end of year	303,614	297,018	-2.17%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	225,078	199,164	-11.51%
18	Actual return on plan assets	17,567	25,557	45.48%
19	Acquisition			
20	Employer contribution	15,000	15,000	
21	Benefits paid	(14,786)	(14,643)	0.97%
22	Expenses paid	(299)		100.00%
23	Fair value of plan assets at end of year	242,560	225,078	-7.21%
24	**Funded Status**	(61,054)	(71,940)	-17.83%
25	Unrecognized net actuarial loss	56,686	63,907	12.74%
26	Unrecognized prior service cost	3,098	3,751	21.08%
27	Unrecognized net transition obligation/(asset)			
28	Prepaid (accrued) benefit cost	(1,270)	(4,282)	-237.17%
29				
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	6.35%	6.15%	-3.15%
32	Expected return on plan assets	8.50%	8.50%	
33	Rate of compensation increase	4.66%	4.84%	3.86%
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost	10,210	9,806	-3.96%
37	Interest cost	18,038	16,086	-10.82%
38	Expected return on plan assets	(19,217)	(16,997)	11.55%
39	Transition (asset)/obligation recognition			
40	Amortization of prior service cost	654	653	-0.15%
41	Recognized net actuarial loss	2,603	3,300	26.78%
42	Net periodic benefit cost	12,288	12,848	4.56%
43				
44	**Montana Intrastate Costs:**			
45	Pension Costs			
46	Pension Costs Capitalized	not available by state		
47	Accumulated Pension Asset (Liability) at Year End			
48	**Number of Company Employees:**			
49	Covered by the Plan	2,632	2,616	-0.61%
50	Not Covered by the Plan			
51	Active	1,403	1,405	0.14%
52	Retired	929	910	-2.05%
53	Deferred Vested Terminated	300	301	0.33%

Other Post Employment Benefits (OPEBS)

Year: 2007

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: ___________			
4	Order number: ___________			
5	Amount recovered through rates			
6	**Weighted-average Assumptions as of Year End**			
7	Discount rate	6.20%	6.15%	-0.81%
8	Expected return on plan assets	8.50%	8.50%	
9	Medical Cost Inflation Rate	6.00%	6.00%	
10	Actuarial Cost Method		Proj Unit Credit	#VALUE!
11	Rate of compensation increase			
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13				
14				
15	**Describe any Changes to the Benefit Plan:**			
16				
17	TOTAL COMPANY			
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year	33,632	32,710	-2.74%
20	Service cost	672	639	-4.91%
21	Interest Cost	2,159	1,956	-9.40%
22	Plan participants' contributions			
23	Amendments	(1,601)		100.00%
24	Actuarial Gain	3,197	1,914	-40.13%
25	Benefits paid	(3,707)	(3,557)	4.05%
26	Expenses paid		(30)	#DIV/0!
27	Benefit obligation at end of year	34,352	33,632	-2.10%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	20,878	18,378	-11.97%
30	Actual return on plan assets	1,840	2,530	37.50%
31	Acquisition			
32	Employer contribution			
33	Benefits paid			
34	Expenses paid		(30)	#DIV/0!
35	Fair value of plan assets at end of year	22,718	20,878	-8.10%
36	**Funded Status**	(11,634)	(12,754)	-9.63%
37	Unrecognized net actuarial loss	2,872	2,084	-27.44%
38	Unrecognized prior service cost	2,526	3,031	19.99%
39	Prepaid (accrued) benefit cost	(6,236)	(7,639)	-22.50%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	672	639	-4.91%
42	Interest cost	2,159	1,956	-9.40%
43	Expected return on plan assets	(1,775)	(1,562)	12.00%
44	Amortization of prior service cost	505	505	
45	Recognized net actuarial loss	193	90	-53.37%
46	Net periodic benefit cost	1,754	1,628	-7.18%
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA	34,352	33,632	-2.10%
49	Amount Funded through 401(h)			
50	Amount Funded through Other ___________			
51	TOTAL	34,352	33,632	-2.10%
52	Amount that was tax deductible - VEBA			
53	Amount that was tax deductible - 401(h)			
54	Amount that was tax deductible - Other ___________			
55	TOTAL	34,352	33,632	-2.10%

Other Post Employment Benefits (OPEBS) Continued

Year: 2007

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	2,463	2,384	-3.21%
3	Not Covered by the Plan			
4	Active	1,742	1,666	-4.36%
5	Retired	721	718	-0.42%
6	Spouses/Dependants covered by the Plan			
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost			
11	Interest Cost	not available by state		
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost	not available by state		
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ____________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Confidential Schedule						
2							
3							
4							
5							
6							
7							
8							
9							
10							

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	G.G. Ely Chairman and CEO (retired effective 12/31/07)	715,000	98,456	1,345,177	2,158,633	3,325,275	-35%
2	S. L. Morris President and COO (Chairman, President and CEO effective 1/1/08)	452,461	43,146	668,519	1,164,126	1,115,496	4%
3	M.K. Malquist Executive Vice President and CFO	350,000	32,130	417,230	799,360	1,096,256	-27%
4	M.M. Durkin Senior Vice President General Counsel and Chief Compliance Officer	264,992	24,326	313,344	602,662	724,126	-17%
5	K.S. Feltes Senior Vice President and Corporate Secretary	213,192	21,114	260,706	495,012	N/A	#VALUE!
6	D. J. Meyer Vice President and Chief Counsel for Reg and Gov Affairs	240,000	14,688	248,186	502,874	692,620	-27%
	Other compensation includes stock-based awards and the change in pension and non-qualified deferred compensation.						

BALANCE SHEET

Year: 2006

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Electric Plant in Service	2,910,719,671	3,104,139,720	-6%
4	101.1	Property Under Capital Leases	5,525,291	5,525,291	
5	102	Electric Plant Purchased or Sold			
6	104	Electric Plant Leased to Others			
7	105	Electric Plant Held for Future Use		39,828	-100%
8	106	Completed Constr. Not Classified - Electric			
9	107	Construction Work in Progress - Electric	89,177,799	75,679,838	18%
10	108	(Less) Accumulated Depreciation	(995,281,671)	(1,057,750,680)	6%
11	111	(Less) Accumulated Amortization	(11,916,076)	(14,017,595)	15%
12	114	Electric Plant Acquisition Adjustments	22,211,433	22,211,433	
13	115	(Less) Accum. Amort. Elec. Acq. Adj.	(17,158,560)	(18,269,132)	6%
14	120	Nuclear Fuel (Net)			
15		**TOTAL Utility Plant**	2,003,277,887	2,117,558,703	-5%
16					
17	**Other Property & Investments**				
18	121	Nonutility Property	4,670,391	4,670,595	0%
19	122	(Less) Accum. Depr. & Amort. for Nonutil. Prop.	(878,680)	(897,192)	2%
20	123	Investments in Associated Companies	13,903,000	13,903,000	
21	123.1	Investments in Subsidiary Companies	247,190,561	71,371,272	246%
22	124	Other Investments	31,166,335	28,691,550	9%
23	128	Other Special Funds	13,360,954	15,878,558	-16%
		Long-Term Derivative Instruments	25,574,531	55,312,881	-54%
24		**TOTAL Other Property & Investments**	334,987,092	188,930,664	77%
25					
26	**Current & Accrued Assets**				
27	131	Cash	(3,021,873)	5,264,119	-157%
28	132-134	Special Deposits	4,042,325	5,668,267	-29%
29	135	Working Funds	684,345	679,537	1%
30	136	Temporary Cash Investments	667,445	2,608,103	-74%
31	141	Notes Receivable			
32	142	Customer Accounts Receivable	89,325,500	87,238,080	2%
33	143	Other Accounts Receivable	9,714,601	9,920,307	-2%
34	144	(Less) Accum. Provision for Uncollectible Accts.	(2,730,352)	(2,965,676)	8%
35	145	Notes Receivable - Associated Companies	7,198,865		#DIV/0!
36	146	Accounts Receivable - Associated Companies	1,465,217	502,535	192%
37	151	Fuel Stock	2,121,931	2,213,923	-4%
38	152	Fuel Stock Expenses Undistributed			
39	153	Residuals			
40	154	Plant Materials and Operating Supplies	14,019,070	17,365,306	-19%
41	155	Merchandise			
42	156	Other Material & Supplies			
43	157	Nuclear Materials Held for Sale			
44	163	Stores Expense Undistributed			
	164	Gas Storage	12,912,139	13,414,238	-4%
45	165	Prepayments	6,467,948	6,438,702	0%
46	171	Interest & Dividends Receivable	4,259		#DIV/0!
47	172	Rents Receivable	327,042	509,924	-36%
48	174	Miscellaneous Current & Accrued Assets	162,032	6,153,636	-97%
	176	Derivative Instruments Assets - Hedges	36,402,843	67,390,448	
49		Long-Term Derivative Instruments	(25,574,531)	(55,312,881)	54%
50		**TOTAL Current & Accrued Assets**	154,188,806	167,088,568	-8%

BALANCE SHEET

Year: 2006

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Assets and Other Debits (cont.)**			
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	17,931,388	11,576,174	55%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	182.3	Other Regulatory Assets	323,816,436	281,620,776	
10	183	Prelim. Survey & Investigation Charges	8,645,616	234,518	3587%
11	184	Clearing Accounts	8,046		#DIV/0!
12	185	Temporary Facilities			
13	186	Miscellaneous Deferred Debits	31,297,127	40,642,265	-23%
14	187	Deferred Losses from Disposition of Util. Plant			
15	188	Research, Devel. & Demonstration Expend.			
16	189	Unamortized Loss on Reacquired Debt	28,622,766	20,965,705	37%
17	190	Accumulated Deferred Income Taxes	55,602,315	90,823,103	-39%
	191	Unrecovered Purchased Gas Costs	18,275,674	2,374,110	
18		**TOTAL Deferred Debits**	484,199,368	448,236,651	8%
19					
20		**TOTAL Assets & Other Debits**	2,976,653,153	2,921,814,586	2%
		Account Title	Last Year	This Year	% Change
20					
21		**Liabilities and Other Credits**			
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	722,039,406	727,945,794	-1%
26	202	Common Stock Subscribed			
27	204	Preferred Stock Issued	-	-	
28	205	Preferred Stock Subscribed			
29	207	Premium on Capital Stock			
30	211	Miscellaneous Paid-In Capital		2,281,868	-100%
31	213	(Less) Discount on Capital Stock			
32	214	(Less) Capital Stock Expense	(6,419,099)	(3,294,916)	-95%
33	215	Appropriated Retained Earnings	168,082,338	221,313,566	-24%
34	216	Unappropriated Retained Earnings	51,109,032	(14,672,673)	448%
35	217	(Less) Reacquired Capital Stock			
	219	Accumulated Other Comprehensive Income	(17,965,585)	(19,607,486)	
36		**TOTAL Proprietary Capital**	916,846,092	913,966,153	0%
37					
38	**Long Term Debt**				
39					
40	221	Bonds	685,196,931	671,733,175	2%
41	222	(Less) Reacquired Bonds			
42	223	Advances from Associated Companies	115,203,000	114,603,000	1%
43	224	Other Long Term Debt	311,600,402	273,010,231	14%
44	225	Unamortized Premium on Long Term Debt	257,617	248,733	4%
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.	(1,709,479)	(1,328,472)	-29%
46		**TOTAL Long Term Debt**	1,110,548,471	1,058,266,667	5%

BALANCE SHEET

Year: 2006

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Total Liabilities and Other Credits (cont.)**			
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent	394,921	75,206	425%
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	954,409	344,000	177%
9	228.3	Accumulated Provision for Pensions & Benefits	102,083,620	90,554,881	13%
10	228.4	Accumulated Misc. Operating Provisions		1,826,000	-100%
11		Long-Term Derivative Instruments	15,318,835	12,400,978	24%
	230	Asset Retirement Obligations	4,809,738	3,990,011	
12		**TOTAL Other Noncurrent Liabilities**	123,561,523	109,191,076	13%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable	4,000,000		#DIV/0!
17	232	Accounts Payable	112,367,144	114,760,498	-2%
18	233	Notes Payable to Associated Companies		2,182,637	-100%
19	234	Accounts Payable to Associated Companies	980,544	600,647	63%
20	235	Customer Deposits	6,463,634	6,331,722	2%
21	236	Taxes Accrued	(4,887,161)	(4,717,808)	-4%
22	237	Interest Accrued	11,594,861	12,577,801	-8%
23	238	Dividends Declared			
24	241	Tax Collections Payable	2,651	252	952%
25	242	Miscellaneous Current & Accrued Liabilities	63,245,923	41,016,254	54%
26	243	Obligations Under Cap. Leases - Current	281,894	295,029	-4%
27	245	Derivative Instrument Liabilities - Hedges	88,797,291	31,649,965	181%
28		Long-Term Derivative Instruments	(15,318,835)	(12,400,978)	-24%
29		**TOTAL Current & Accrued Liabilities**	267,527,946	192,296,019	39%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	1,087,069	1,265,933	-14%
34	253	Other Deferred Credits	17,616,522	18,072,332	-3%
35	254	Other Regulatory Liabilities	18,246,960	65,481,339	-72%
36	255	Accumulated Deferred Investment Tax Credits	472,344	423,036	12%
37	257	Unamortized Gain on Reacquired Debt	3,282,969	3,528,194	-7%
38	281-283	Accumulated Deferred Income Taxes	517,463,257	559,323,837	-7%
39		**TOTAL Deferred Credits**	558,169,121	648,094,671	-14%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		2,976,653,153	2,921,814,586	2%

NOTES TO 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 Corp. generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Corp. has electric generating facilities in western Montana and northern Oregon. Avista Corp. 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. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America.

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 financial statements include the assets, liabilities, revenues and expenses of the Company. As required by the Federal Energy Regulatory Commission (FERC), the Company accounts for its investment in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by accounting principles generally accepted in the United States of America. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants. In addition, under the requirements of the FERC, there are differences from accounting principles generally accepted in the United States of America in the presentation of (1) current portions of long-term debt, short-term borrowings, and preferred stock, (2) assets and liabilities for cost of removal of assets, (3) assets held for sale, (4) regulatory assets and liabilities, (5) retained earnings, and (6) comprehensive income.

Use of Estimates
The preparation of the 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 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 financial statements and thus actual results could differ from the amounts reported and disclosed herein.

System of Accounts
The accounting records of the Company's utility operations are maintained in accordance with the uniform system of accounts prescribed by the 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.

Operating Revenues
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.

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 Statement of Financial Accounting Standards (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.

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. 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 23 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

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 22 for earnings per common share calculations.

Cash and Cash Equivalents

For the purposes of the 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.

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	$2,730	$3,228	$2,810
Additions expensed during the year	3,078	2,888	2,752
Net deductions	(2,842)	(3,386)	(2,334)
Allowance as of the end of the year	$2,966	$2,730	$3,228

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.

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 Statements of Income. The Company generally is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a fair return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC generally does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was 9.11 percent in 2007 and 2006 and 9.72 percent for 2005. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

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

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

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

Regulatory Deferred Charges and Credits
The Company prepares its 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 Balance Sheets. These costs and/or obligations are not reflected in the statement of income until the period during which matching revenues are recognized.

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

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

The Company's primary regulatory assets include:

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

Regulatory liabilities include:

- 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.

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 Corp. 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 Corp. 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 Corp. 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 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 Corp. 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 Corp. 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 Corp. accrues interest on deferred power costs in the Washington jurisdiction at a rate, which is adjusted semi-annually, of 7.8 percent as of December 31, 2007. Total deferred power costs for Washington customers were $58.5 million as of December 31, 2007 and $70.2 million as of December 31, 2006.

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

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

Avista Corp. 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 Corp. 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 Corp. 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 Corp. 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 Corp. 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 proceeds from issuance of common stock on the Statement of Cash Flows. See Note 23 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 11 for further information.

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

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

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

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

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option is elected would be reported in net income. The Company will be required to adopt SFAS No. 159 in 2008.

The Company does not plan to use the fair value option under SFAS No. 159 and as such does not expect SFAS No. 159 to impact its financial condition and results of operations.

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

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

NOTE 3. DISPOSITION OF AVISTA ENERGY

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

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

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

Proceeds from the transaction included cash consideration for the net assets acquired by Shell Energy and the liquidation of the remaining net current assets of Avista Energy not sold to Shell Energy (primarily receivables, restricted cash and deposits with counterparties).

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 Corp., 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 Corp., 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 24), existing litigation, tax liabilities, matters with respect to storage rights at Jackson Prairie, and any potential issues associated with the power purchase agreement for the Lancaster Plant. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

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

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

Avista Energy made customary representations, warranties and covenants in the purchase and sale agreement. Avista Corp. and its subsidiaries agreed that for a period of 60 calendar months beginning on the closing of the transaction (June 30, 2007), neither Avista Corp. nor any of its subsidiaries will form or participate through ownership or any alliance, or internally, develop capabilities to replicate the business activities of Avista Energy within the region of the Western Electric Coordinating Council. This restriction has certain exceptions primarily related to any assets or contracts retained by Avista Energy and any current corporate activities outside of Avista Energy, including any resource optimization or associated trading or hedging activities of the character currently being conducted by Avista 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. 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. 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. 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 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. 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 13). 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 is exposed to risks relating to, but not limited to:

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

Avista Corp. utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these exposures. 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 Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available resources to serve Avista Corp.'s load obligations and uses its existing resources to capture available economic value. Avista Corp. 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 Corp. 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 Corp. 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 Corp.'s resources, and
- other wholesale transactions to capture the value of generation and transmission resources.

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

As part of its resource optimization process described above, Avista Corp. 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 Corp. enters into forward contracts to purchase or sell electricity and natural gas. Under these forward contracts, Avista Corp. 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 Corp. 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 Corp.'s 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 Corp. 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 Corp. to not recognize the unrealized gain or loss on utility derivative commodity instruments in the 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.

Market Risk

Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Market risk is influenced to the extent that the performance or nonperformance by market participants of their contractual obligations and commitments affect the supply of, or demand for, the commodity. The Company manages the market risks inherent in their activities according to the risk management policy established by the Company's Risk Management Committee.

Credit Risk

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

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

Should a counterparty, customer or supplier fail to perform, the Company may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices. The Company seeks to mitigate credit risk by:

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

These credit policies include an evaluation of the financial condition and credit ratings of counterparties, collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. The Company also uses standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty.

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

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

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

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

In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to minimize capital requirements.

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

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

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

NOTE 7. CASH DEPOSITS WITH AND FROM COUNTERPARTIES

Cash deposits from counterparties totaled $12.5 million as of December 31, 2007 and $39.4 million as of December 31, 2006. These funds were held by Avista Corp. to mitigate the potential impact of counterparty default risk. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of non-cash collateral.

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

NOTE 8. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Statements of Income. The Company's share of utility plant in service for Colstrip was $329.6 million and accumulated depreciation was $197.7 million as of December 31, 2007.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The Company follows SFAS No. 143, "Accounting for Asset Retirement Obligations," and records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded since asset retirement costs are recovered through rates charged to customers. The regulatory assets do not earn a return.

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

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

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

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

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

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

NOTE 10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees. Individual benefits under this plan are based upon the employee's years of service and average compensation as specified in the plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $15 million in cash to the pension plan in each of 2007, 2006 and 2005. The Company expects to contribute at least $15 million to the pension plan in 2008.

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

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

The Finance Committee of the Company's Board of Directors:

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

The Company has contracted with an investment consultant who is responsible for managing/monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by the Finance Committee to ensure compliance with investment policy objectives and strategies. Pension plan assets are invested primarily in marketable debt and equity securities. Pension plan assets may also be invested in real estate, absolute return, venture capital/private equity and commodity funds. In seeking to obtain the desired return to fund the pension plan, the Finance Committee has established investment allocation percentages by asset classes as indicated in the table in this Note.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. The market-related value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices).

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

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

The market-related value of plan assets was determined as of December 31, 2007 and 2006.

In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

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

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The Company elected to amortize the transition obligation of $34.5 million over a period of twenty years, beginning in 1993. The Company expects that benefit payments under the postretirement benefit plan will be $3.1 million in 2008, $3.0 million in 2009, $2.9 million in 2010, $2.8 million in 2011 and $2.7 million in 2012. For the ensuing five years (2013 through 2017), the Company expects that benefit payments under the postretirement benefit plan will total $12.3 million. The Company expects to contribute $3.1 million to the postretirement benefit plan in 2008, representing expected benefit payments to be paid during the year.

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

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer's designated beneficiary will receive a payment equal to twice the executive officer's annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer's total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits. Effective December 31, 2007, this plan was amended to eliminate a provision that allowed an executive officer to elect for their beneficiaries to receive one quarter of such payment each year over a ten-year period commencing within 30 days of the executive officer's death. The plan was also amended to provide that those who become executive officers after December 31, 2007 will no longer be eligible to receive benefits after retirement. The amendments to the plan reduced the benefit obligation by $1.6 million.

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

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2007 by $1.6 million and the service and interest cost by $0.2 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2007 by $1.4 million and the service and interest cost by $0.1 million.

The Company and its most significant subsidiaries have salary deferral 401(k) plans that are defined contribution plans and cover substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The respective company matches a portion of the salary deferred by each participant according to the schedule in the respective plan. Employer matching contributions were $4.6 million in 2007, $4.4 million in 2006 and $4.1 million in 2005.

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust. At December 31, 2007 and 2006, there were deferred compensation assets of $12.1 million and $12.6 million included in other special funds and corresponding deferred compensation liabilities of $12.1 million and $12.6 million included in other deferred credits on the Balance Sheets.

NOTE 11. ACCOUNTING FOR INCOME TAXES

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

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

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

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon, Montana and California. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has examined the Company's 2001, 2002 and 2003 federal income tax returns. Despite those tax years still remaining open, all issues were resolved with the exception of the timing for the deductions of certain indirect overhead costs. The IRS is currently conducting an examination of the Company's 2004 and 2005 federal income tax returns. This examination could result in a change in the liability for uncertain tax positions. However, an estimate of the range of any such possible change cannot be made at this time. The Company does not believe that any open tax years with respect to state income taxes could result in any adjustments that would be significant to the financial statements.

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

Due to the revenue ruling and related regulations, the IRS has disallowed the tax deduction of indirect overhead expenses during their examination of the Company's 2001, 2002 and 2003 federal income tax returns. The Company believes that the tax deductions claimed on tax returns were appropriate based on the applicable statutes and regulations in effect at the time. Avista Corp. appealed the proposed IRS adjustment on April 19, 2006. The Company's appeal is being reviewed by the IRS Appeals Division. The Company repaid a portion of the previous tax deductions through tax payments in 2005 and 2006. There can be no assurance that the Company's position will prevail. However, it is not expected to have a significant effect on the Company's net income.

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

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

NOTE 12. ENERGY PURCHASE CONTRACTS

Avista Corp. has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The termination dates of the contracts range from one month to the year 2055. Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in operation expenses in the Statements of Income, were $733.5 million in 2007, $682.5 million in 2006 and $652.2 million in 2005. The following table details Avista Corp.'s future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

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

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

In addition, Avista Corp. has operational agreements, settlements and other contractual obligations for its generation, transmission and distribution facilities. The expenses associated with these agreements are reflected as operation expenses and maintenance expenses in the Statements of Income. The following table details future contractual commitments for these agreements (dollars in thousands):

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

Avista Corp. has fixed contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the fixed contracts obligate Avista Corp. to pay certain minimum amounts (based in part on the debt service requirements of the PUD) whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in operation expenses in the Statements of Income. Expenses under these PUD contracts were $18.0 million in 2007, $13.1 million in 2006 and $9.0 million in 2005.

Information as of December 31, 2007 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs (1)	Debt Service Costs (1)	Bonds Outstanding	Expiration Date
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$ 2,181	$1,007	$ 1,796	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,891	795	4,506	2018
Grant County PUD:						
Priest Rapids Project	3.3%	55,000	9,534	882	10,064	2055
Wanapum Project	8.2%	75,000	4,430	2,949	18,526	2055
Totals		197,000	$18,036	$5,633	$34,892	

(1) The annual costs will change in proportion to the percentage of output allocated to Avista Corp. in a particular year. Amounts represent the operating costs for the year 2007. Debt service costs are included in annual costs.

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

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

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

NOTE 13. COMMITTED LINE OF CREDIT

The Company has a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company can request the issuance of up to $320.0 million in letters of credit. Total letters of credit outstanding were $34.8 million as of December 31, 2007 and $77.1 million as of December 31, 2006. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Corp. for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2007, the Company was in compliance with this covenant with a ratio of 2.70 to 1. The committed line of credit agreement also has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 70 percent at the end of any fiscal quarter. As of December 31, 2007, the Company was in compliance with this covenant with a ratio of 53.8 percent. If the proposed change in organization becomes effective, the committed line of credit will remain at Avista Corp.

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

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

NOTE 14. BONDS AND OTHER LONG-TERM DEBT

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

Maturity Year	Description	Interest Rate	2007	2006
2007	Secured Medium-Term Notes	5.99%	$ -	$ 13,850
2008	Secured Medium-Term Notes	6.06%-6.95%	45,000	45,000
2010	Secured Medium-Term Notes	6.67%-8.02%	35,000	35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes (1)	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (2)	5.00%	66,700	66,700
2034	Secured Pollution Control Bonds (2)	5.13%	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured long-term debt		666,700	680,550
2007	Unsecured Medium-Term Notes	7.90%-7.94%	-	12,000
2008	Unsecured Senior Notes	9.75%	272,860	272,860
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Total unsecured long-term debt		276,960	288,960
	Interest rate swaps		1,083	1,037
	Committed line of credit		-	4,000
	Preferred stock		-	26,250
	Total bonds and other long-term debt		$944,743	$1,000,797

(1) These Secured Medium-Term Notes with a maturity date of June 2028 are puttable at the option of the security holders in June 2008.

(2) These Secured Pollution Control Bonds 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, the Company will be required to purchase the outstanding bonds.

The following table details future long-term debt maturities (2008 maturities include amounts discussed at (1) and (2) above), not including interest rate swaps (dollars in thousands):

Year	2008	2009	2010	2011	2012	Thereafter	Total
Debt maturities	$426,560	$ -	$35,000	$ -	$7,000	$475,100	$943,660

Substantially all utility properties owned by the Company are subject to the lien of the Company's various mortgage indentures. Under the Mortgage and Deed of Trust securing the Company's First Mortgage Bonds (including Secured Medium-Term Notes), the Company may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of: 1) 70 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or 2) an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or 3) deposit of cash; provided, however, that the Company may not issue any additional First Mortgage Bonds unless the Company's "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, an on all indebtedness of prior rank. As of December 31, 2007, property additions and retired bonds would have entitled the Company to issue $953.3 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended

December 31, 2007, the net earnings test would limit the principal amount of additional bonds the Company could issue to $609.5 million.

See Note 13 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its $320.0 million committed line of credit.

NOTE 15. ADVANCES FROM ASSOCIATED COMPANIES

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

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. The annual distribution rate paid during 2007 ranged from 5.999 percent to 6.455 percent. As of December 31, 2007, the annual distribution rate was 5.999 percent. Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II on or after June 1, 2007 and mature on June 1, 2037; however, this is limited by an agreement under the Company's 9.75 percent Senior Notes that mature on June 1, 2008. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount with respect to, the Preferred Trust Securities to the extent that AVA Capital Trust III and Avista Capital II have funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed.

NOTE 16. INTEREST RATE SWAP AGREEMENTS

Avista Corp. enters into forward-starting interest rate swap agreements to manage the risk associated with changes in interest rates and the impact on future interest payments. These interest rate swap agreements relate to the interest payments for the anticipated issuances of debt. These interest rate swap agreements are considered hedges against fluctuations in future cash flows associated with changes in interest rates in accordance with SFAS No. 133.

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

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

NOTE 17. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from one to forty-five years. Rental expense under operating leases was $2.0 million in 2007, $2.5 million in 2006 and $8.0 million in 2005. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2007 were as follows (dollars in thousands):

Year ending December 31:	2008	2009	2010	2011	2012	Thereafter	Total
Minimum payments required	$1,538	$1,380	$412	$201	$117	$2,798	$6,446

NOTE 18. GUARANTEES

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

Avista Power, through its equity investment in Rathdrum Power, LLC (RP LLC), was a 49 percent owner of the Lancaster Plant, which commenced commercial operation in September 2001. In October 2006, Avista Power completed the sale of its investment in RP LLC for close to book value. The output from the Lancaster Plant is contracted to Avista Energy through 2026 under a power purchase agreement. Avista Corp. has guaranteed the power purchase agreement for the performance of Avista Energy. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, the Company expects that these rights and obligations will be transferred to Avista Corp., subject to future approval.

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

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

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

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

NOTE 20. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying values of cash, special deposits, working funds, temporary cash investments, accounts and notes receivable, accounts payable and the committed line of credit are reasonable estimates of their fair values. Energy commodity derivative assets and liabilities, as well as derivatives related to interest rate swap agreements, are reported at estimated fair value on the Balance Sheets. The following table sets forth the estimated fair value and carrying value of the Company's long-term debt (including current portion, but excluding capital leases), long-term debt to affiliated trusts and preferred stock subject to mandatory redemption as of December 31, 2007 and 2006 (dollars in thousands):

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

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

NOTE 21. COMMON STOCK

In November 1999, the Company adopted a shareholder rights plan pursuant to which holders of common stock outstanding on February 15, 1999, or issued thereafter, were granted one preferred share purchase right (Right) on each outstanding share of common stock. Each Right, initially evidenced by and traded with the shares of common stock, entitles the registered holder to purchase one one-hundredth of a share of preferred stock of the Company, without par value, at a purchase price of $70, subject to certain adjustments, regulatory approval and other specified conditions. The Rights will be exercisable only if a person or group acquires 10 percent or more of the outstanding shares of common stock or commences a tender or exchange offer, the consummation of which would result in the beneficial ownership by a person or group of 10 percent or more of the outstanding shares of common stock. Upon any such acquisition, each Right will entitle its holder to purchase, at the purchase price, that number of shares of common stock or preferred stock of the Company (or, in the case of a merger of the Company into another person or group, common stock of the acquiring person or group) that has a market value at that time equal to twice the purchase price. In no event will the Rights be exercisable by a person that has acquired 10 percent or more of the Company's common stock. The Rights may be redeemed, at a redemption price of $0.01 per Right, by the Board of Directors of the Company at any time until any person or group has acquired 10 percent or more of the common stock. In connection with the proposed statutory share exchange (see Note 25), the shareholder rights plan was amended to provide that the Rights will expire upon the earlier of the effective time of the statutory share exchange or March 31, 2009 (the originally scheduled expiration date).

The Company has a Dividend Reinvestment and Stock Purchase Plan under which the Company's shareholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's common stock at current market value.

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

In December 2006, the Company entered into a sales agency agreement with a sales agent, to issue up to 2 million shares of its common stock from time to time. As of February 25, 2008, the Company has not issued any shares under the sales agency agreement.

NOTE 22. EARNINGS PER COMMON SHARE

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

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

Total stock options outstanding that were not included in the calculation of diluted earnings per common share were 303,950 for 2007, 26,200 for 2006 and 695,500 for 2005. These stock options were excluded from the calculation because they were antidilutive based on the fact that the exercise price of the stock options was higher than the average market price of Avista Corp. common stock during the respective period. In addition, contingent stock awards of 318,900 were outstanding as of December 31, 2005, which were not included in basic or diluted shares because the performance conditions were not satisfied.

NOTE 23. STOCK COMPENSATION PLANS

1998 Plan

In 1998, the Company adopted, and shareholders approved, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, officers and non-employee directors of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. The Company has available a maximum of 3.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2007, 0.9 million shares were remaining for grant under this plan.

2000 Plan

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of non-employee directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan. However, the Company currently does not plan to issue any further options or securities under the 2000 Plan. As of December 31, 2007, 1.7 million shares were remaining for grant under this plan.

Stock Compensation

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

On January 1, 2006, the Company adopted SFAS No. 123R, which supersedes APB No. 25 and SFAS No. 123 and their related implementation guidance. The statement requires that the compensation cost relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. The Company adopted SFAS No. 123R using the modified prospective method and, accordingly, financial statement amounts for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. The Company recorded stock-based compensation expense of $2.5 million for 2007 and $4.0 million for 2006. The total income tax benefit recognized in the Statements of Income was $1.0 million for 2007 and $1.5 million for 2006.

Stock Options

The fair value of stock option awards was calculated using the Black Scholes option pricing model. This model requires the use of subjective assumptions, including stock price volatility, dividend yield, risk-free interest rate and expected time to exercise. See Note 1 for disclosure of pro forma net income and earnings per common share for 2005. The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

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

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

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

Total cash received from the exercise of stock options was $1.9 million for 2007 and $9.9 million for 2006. As of December 31, 2007 and 2006, the Company's stock options were fully vested and expensed.

Restricted Shares

Restricted shares vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the CEO's restricted shares to vest. During the vesting period, employees are entitled to dividend equivalents which are paid when dividends on the Company's common stock are declared. Restricted stock is valued at the close of market of the Company's common stock on the grant date. The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2007 was one year.

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

	2007	2006
Unvested shares at beginning of year	36,180	-
Shares granted	31,860	36,260
Shares cancelled	(19,936)	(80)
Shares vested	(19,967)	-
Unvested shares at end of year	28,137	36,180
Weighted average fair value at grant date	$25.60	$21.32
Unrecognized compensation expense at end of year (in thousands)	$517	$439
Intrinsic value, unvested shares at end of year (in thousands)	$606	$916
Intrinsic value, shares vested during the year (in thousands)	$461	$ -

Performance Shares

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

Performance share awards entitle the grantee to shares of common stock or cash payable once the service condition is satisfied. Based on attainment of the performance condition, grantees may receive 0 to 150 percent of the original shares granted. The performance condition used is the Company's Total Shareholder Return (TSR) performance over a three-year period as compared against other utilities; under SFAS 123R this is considered a market based condition. Performance shares may be settled in common stock or cash at the discretion of the Company. Historically, the Company has settled these awards through issuance of stock and intends to continue this practice. These awards vest at the end of the three-year period. Under Statement SFAS 123R, performance shares are equity awards with a market based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is rendered, regardless of when, if ever, the market condition is satisfied.

The Company measures (at the grant date) the estimated fair value of performance shares granted in accordance with the provisions of SFAS No. 123R. The fair value of each performance share award was estimated on the date of grant using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to a peer group. Expected volatility was based on the historical volatility of Avista Corp. common stock over a three-year period. The expected term of the performance shares is three years based on the performance cycle. The risk-free interest rate was based on the U.S. Treasury yield at the time of grant. The compensation expense on these awards will only be adjusted for changes in forfeitures. The following summarizes the weighted average assumptions used to determine the fair value of performance shares and related compensation costs as well as the resulting estimated fair value of performance shares granted:

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

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

The following summarizes performance share activity:

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

The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2007 was 1.4 years. Unrecognized compensation expense as of December 31, 2007 will be recognized during 2008 and 2009. The following summarizes the impact of the market condition on the vested performance shares:

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

In 2007, 2006 and 2005, the number of performance shares vested was adjusted by (35) percent, 22 percent and 20 percent due to the performance condition achieved. Shares earned under this plan are distributed to participants in the quarter following vesting.

Awards outstanding under the performance share grants include a dividend component that is paid in cash. This component of the performance share grants is accounted for as a liability award under the guidance of SFAS No. 123R. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, and the change in the value of the Company's common stock relative to an external benchmark. Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2007 and 2006, the Company had recognized compensation expense and a liability of $0.4 million and $0.7 million related to the dividend component of performance share grants.

NOTE 24. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. With respect to these proceedings, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. With respect to matters that affect Avista Corp.'s regulated utility operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the rate making process. With respect to matters discussed in this Note that affect Avista Energy (particularly the California Refund Proceeding), any potential liabilities or refunds remain at Avista Corp. and/or its subsidiaries and were not assumed by Shell Energy and/or its affiliates.

Federal Energy Regulatory Commission Inquiry

On April 19, 2004, the FERC issued an order approving the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) reached by Avista Corp., Avista Energy and the FERC's Trial Staff with respect to an investigation into the activities of Avista Corp. and Avista Energy in western energy markets during 2000 and 2001. In the Agreement in Resolution, the FERC Trial Staff stated that its investigation found: (1) no evidence that any executives or employees of Avista Corp. or Avista Energy knowingly engaged in or facilitated any improper trading strategy; (2) no evidence that Avista Corp. or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) that Avista Corp. and Avista Energy did not withhold relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001. In April 2005 and June 2005, the California Parties and the City of Tacoma, respectively, filed petitions for review of the FERC's decisions approving the Agreement in Resolution with the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). Based on the FERC's order approving the Agreement in Resolution and the FERC's denial of rehearing requests, the Company does not expect that this proceeding will have any material adverse effect on its financial condition, results of operations or cash flows.

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

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

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

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

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

California Refund Proceeding
In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) during the period from October 2, 2000 to June 20, 2001 (Refund Period). The findings of the FERC administrative law judge were largely adopted in March 2003 by the FERC. The refunds ordered are based on the development of a mitigated market clearing price (MMCP) methodology. If the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, the FERC has held that the seller would be allowed

to document these costs and limit its refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order and demonstrated an overall revenue shortfall for sales into the California spot markets during the Refund Period after the MMCP methodology is applied to its transactions. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In its February 2007 status report, the CalISO stated that it intends to process Avista Energy's cost offset filing. In November 2007, the CalISO filed an updated status report at the FERC stating that it continues finalizing the financial adjustment phase, in which the CalISO is making adjustments to its refund rerun settlement data to account for fuel cost allowance offsets, cost-based offsets, and interest calculations. The CalISO states that it has finished processing activities associated with the emissions cost and fuel cost offsets.

In 2001, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) defaulted on payment obligations to the CalPX and the CalISO. As a result, the CalPX and the CalISO failed to pay various energy sellers, including Avista Energy. Both PG&E and the CalPX declared bankruptcy in 2001. In March 2002, SCE paid its defaulted obligations to the CalPX. In April 2004, PG&E paid its defaulted obligations into an escrow fund in accordance with its bankruptcy reorganization. Funds held by the CalPX and in the PG&E escrow fund are not subject to release until the FERC issues an order directing such release in the California refund proceeding. As of December 31, 2007, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties.

In addition, in June 2003, the FERC issued an order to review bids above $250 per MW made by participants in the short-term energy markets operated by the CalISO and the CalPX from May 1, 2000 to October 2, 2000. In May 2004, the FERC provided notice that Avista Energy was no longer subject to this investigation. In March and April 2005, the California Parties and PG&E, respectively, petitioned for review of the FERC's decision by the Ninth Circuit. In addition, many of the other orders that the FERC has issued in the California refund proceedings are now on appeal before the Ninth Circuit. Some of those issues were consolidated as a result of a case management conference conducted in September 2004. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round is limited to three issues: (1) which parties are subject to the FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the Federal Power Act (FPA); (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California Refund Case. In its Order on Remand, issued in October 2007, the FERC ordered the CalISO and the CalPX to complete their refund calculations, including all entities that participated in the CalISO/CalPX markets (including those amounts that would have been paid by municipal utility entities for their sales into the CalISO and the CalPX spot markets during the refund period). The FERC then directed the CalISO to reduce refunds owed to refund recipients by the amounts attributable to municipal sales to the California markets.

In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 Refund Proceeding, but remanded to the FERC its decision not to consider a FPA section 309 remedy for tariff violations prior to October 2, 2000. The Ninth Circuit also granted California's petition for review challenging the FERC's exclusion of the energy exchange transactions as well as the FERC's exclusion of forward market transactions from the California refund proceedings. Petitions for rehearing were filed on November 16, 2007. It is unclear at this time what impact, if any, the Court's remand might have on Avista Energy. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit.

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

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

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000, and June 20, 2001, were just and reasonable. During the hearing, Avista Corp. and Avista Energy vigorously opposed claims that rates for spot market sales were unjust and unreasonable and that the imposition of refunds would be appropriate. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. These equitable factors included the fact that the participants in the Pacific Northwest market include not only utilities and other entities that are subject to FERC jurisdiction, but also a very substantial number of governmental entities that are not subject to FERC jurisdiction with respect to wholesale sales and thus could not be ordered by the FERC to make refunds based on existing law. Seven petitions for review were filed with the Ninth Circuit challenging the merits of the FERC's decision not to order refunds and raising procedural issues.

On August 24, 2007, the Ninth Circuit issued its opinion on the consolidated petitions for review of the Pacific Northwest refund proceeding. The Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. Requests for rehearing were filed on December 17, 2007.

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

California Attorney General Complaint

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the Attorney General of the State of California (California AG) that alleged violations of the Federal Power Act by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's adoption and implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint but directing sellers to re-file certain transaction summaries. It was not clear that Avista Corp. and its subsidiaries were subject to this directive but the Company took the conservative approach and re-filed certain transaction summaries in June and July of 2002. In July 2002, the California AG requested a rehearing on the FERC order, which request was denied in September 2002. Subsequently, the California AG filed a Petition for Review of the FERC's decision with the Ninth Circuit. In September 2004, the Ninth Circuit upheld the FERC's market-based rate authority, but found the requirement that all sales at market-based rates be contained in quarterly reports filed with the FERC to be integral to a market-based rate tariff. The California AG has interpreted the decision as providing authority to the FERC to order refunds in the California refund proceeding for an expanded refund period. The Court's decision leaves to the FERC the determination as to whether refunds are appropriate. In October 2004, Avista Energy joined with others in seeking rehearing of the Court's decision to remand the case back to the FERC for further proceedings. The Court denied the request without explanation on July 31, 2006. A petition for a writ of certiorari with the United States Supreme Court was denied on June 18, 2007. The proceeding is now on remand before the FERC. Based on information currently known to the Company's management, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Wah Chang Complaint

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

State of Montana Proceedings

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

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

Because the resolution of these proceedings remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that these proceedings will have a material adverse effect on its financial condition, results of operations or cash flows.

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

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

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

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

Colstrip Generating Project Complaints
In May 2003, various parties (all of which are residents or businesses of Colstrip, Montana) filed a consolidated complaint against the owners of the Colstrip Generating Project (Colstrip) in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs allege damages to buildings as a result of rising ground water, as well as damages from contaminated waters leaking from the lakes and ponds of Colstrip. The plaintiffs are seeking punitive damages, an order by the court to remove the lakes and ponds and the forfeiture of all profits earned from the generation of Colstrip. The owners of Colstrip have undertaken certain groundwater investigation and remediation measures to address groundwater contamination. These measures include improvements to the lakes and ponds of Colstrip.

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

The complaints were consolidated and a trial date is scheduled for June 2, 2008. The Company intends to continue to work with the other owners of Colstrip in defense of this consolidated complaint. Because the resolution of this consolidated complaint remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect this consolidated complaint will have a material adverse effect on its financial condition, results of operations or cash flows.

Colstrip Royalty Claim
Western Energy Company (WECO) supplies coal to the owners of Colstrip Units 3 & 4 under a Coal Supply Agreement and a Transportation Agreement. Avista Corp. owns a 15 percent interest in Colstrip Units 3 & 4. The Minerals Management Service (MMS) of the United States Department of the Interior issued orders to WECO to pay additional royalties concerning coal delivered to Colstrip Units 3 & 4 via the conveyor belt. The owners of Colstrip Units 3 & 4 take delivery of the coal at the beginning of the conveyor belt. The orders assert that additional royalties are owed to MMS as a result of WECO not paying royalties in connection with revenue received by WECO from the owners of Colstrip Units 3 & 4 under the Transportation Agreement during the period October 1, 1991 through December 31, 2004. WECO's appeal to the MMS for the period through 2001 was substantially denied in March 2005; WECO appealed the orders pertaining to the periods up to 2001 to the Board of Land Appeals of the U.S. Department of the Interior, which appeal was denied on September 12, 2007. WECO also filed an appeal with the MMS pertaining to the period from 2002 to 2004. The entire appeal process could take several years to resolve. The owners of Colstrip Units 3 & 4 are monitoring the appeal process between WECO and MMS. WECO has indicated to the owners of Colstrip Units 3 & 4 that if WECO is unsuccessful in the appeal process, WECO will seek reimbursement of any royalty payments by passing these costs through the Coal Supply Agreement. The owners of Colstrip Units 3 & 4 advised WECO that their position would be that these claims are not allowable costs per the Coal Supply Agreement nor the Transportation Agreement in the event the owners of Colstrip Units 3 & 4 were invoiced for these claims. Presumably, royalty and tax demands for periods of time after the years in dispute and future years will be determined by the outcome of the pending proceedings. Because the resolution of this issue remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. Based on information currently known to the Company's management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. However, the Company would most likely seek recovery, through the rate making process, of any amounts paid.

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

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

Harbor Oil Inc. Site
Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp., as a customer of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed

an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The total cost of the RI/FS is estimated to be $0.6 million and will take approximately 2 1/2 years to complete. The actual cleanup, if any, will not occur until the RI/FS is complete. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the relative volume of waste oil delivered to the Harbor Oil site. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. As such, it is not possible to make an estimate of any liability at this time.

Lake Coeur d'Alene

In July 1998, the United States District Court for the District of Idaho issued its finding that the Coeur d'Alene Tribe of Idaho (Tribe) owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Coeur d'Alene Reservation. This action had been brought by the United States on behalf of the Tribe against the state of Idaho. The Company was not a party to this action. The United States District Court decision was affirmed by the Ninth Circuit. The United States Supreme Court affirmed this decision in June 2001. This ownership decision will result in, among other things, the Company being liable to the Tribe for compensation for the use of reservation lands under Section 10(e) of the Federal Power Act.

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

Spokane River Relicensing

The Company owns and operates six hydroelectric plants on the Spokane River, and five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls, which have a total present capability of 155.7 MW) are under one FERC license and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. Since the FERC was unable to issue new license orders prior to the August 1, 2007 expiration of the current license, an annual license was issued, in effect extending the current license and its conditions until August 1, 2008. The Company has no reason to believe that Spokane River Project operations will be interrupted in any manner relative to the timing of the FERC's actions.

The Company filed a Notice of Intent to Relicense in July 2002. The formal consultation process involving planning and information gathering with stakeholder groups has been underway since that time. The Company filed its new license applications with the FERC in July 2005. The Company requested the FERC to consider a license for Post Falls, which has a present capability of 18 MW, that is separate from the other four hydroelectric plants because Post Falls presents more complex issues that may take longer to resolve than those relating to the rest of the Spokane River Project. If granted, new licenses would have a term of 30 to 50 years. In the license applications, the Company proposed a number of measures intended to address the impact of the Spokane River Project and enhance resources associated with the Spokane River.

Since the Company's July 2005 filing of applications to relicense the Spokane River Project, the FERC has continued various stages of processing the applications. In May 2006, the FERC issued a notice requesting other parties to provide terms and conditions regarding the two license applications. In response to that notice, a number of parties (including the Coeur d'Alene Tribe, the state of Idaho, Washington state agencies, and the United States Department of Interior (DOI)) filed either recommended terms and conditions, pursuant to Sections 10(a) and 10(j) of the Federal Power Act (FPA), or mandatory conditions related to the Post Falls application, pursuant to Section 4(e) of the FPA. The Company's initial estimate of the potential cost of the conditions proposed for Post Falls total between $400 million and $500 million over a 50-year period. For the rest of the Spokane River Project, which is located in Washington, the Company's initial estimate of the cost of meeting the recommended conditions, should they be included in a final license, totaled between $175 million and $225 million over a 50-year period. These cost estimates were based on the preliminary conditions and recommendations.

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

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

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

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

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

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

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

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

The USFWS has listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company is evaluating the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures.

Air Quality

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

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

Compliance with these new and proposed requirements and possible additional legislation or regulations will result in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities. The Company, along with the other owners of Colstrip, completed the first phase of testing on two mercury control technologies. Although the mercury reduction targets as mandated by the Montana DEQ have not been achieved, the owners of Colstrip are encouraged with the preliminary results and believe it should be possible to achieve the required emissions levels with further mercury control system optimization. Preliminary estimates indicate that the Company's share of installation capital costs would be \$1.3 million and annual operations and maintenance costs would increase by \$2.8 million (beginning in mid-2009). The Company will continue to seek recovery, through the rate making process, of the costs to comply with various air quality requirements.

Residential Exchange Program

The residential exchange program is intended to provide access to the benefits of low-cost federal hydroelectricity to residential and small-farm customers of the region's private (investor owned) and public utilities (governmental or customer owned). The Bonneville Power Administration (BPA) administers the residential exchange program under the Northwest Power Act. Previously, Avista Corp. and other private utilities in the Pacific Northwest executed settlement agreements with BPA to resolve each party's rights and obligations under the residential exchange program. These settlements covered payment of benefits for the period October 1, 2001, through September 30, 2011. The payments Avista Corp. received under the agreements with the BPA were passed through to its residential and small-farm customers via a credit to their monthly electric bills.

Several public utilities and other parties filed suit against the BPA in the Ninth Circuit, challenging the validity of the agreements between Avista Corp. and the BPA, as well as BPA's agreements with other private utilities. On May 3, 2007, the Ninth Circuit ruled that the BPA exceeded its authority when it entered into the settlement agreements with private utilities (including Avista Corp.) for the period from 2001 through 2011. The BPA concluded that the Ninth Circuit's decisions created substantial doubt about whether its certifying official could allow continuation of payments under the settlement agreements. Consequently, on May 21, 2007, the BPA notified Avista Corp. and other private utilities that it was immediately suspending payments the BPA made to them pursuant to the settlement agreements. In its May 21, 2007 notice, the BPA indicated that the suspension of payments would continue at least until any requests for rehearing were filed and the Ninth Circuit issued final decisions on those requests for rehearing. On July 18, 2007 Avista Corp. and numerous other parties, including the Public Utility Commission of Oregon and the WUTC, filed petitions for review, and review *en banc*, in the Ninth Circuit, challenging the ruling of the panel that struck down the settlement agreements. The Ninth Circuit subsequently denied these requests. Three private utilities, including Avista Corp., filed a petition for writ of certiorari with the United States Supreme Court.

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

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

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

Other Contingencies

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

The Company routinely assesses, based on in-depth studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who have and have not agreed to a settlement and recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred.

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

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. The State of Montana is examining the status of all water right claims within state boundaries. Claims within the Clark Fork River basin could potentially adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The Company is participating in this extensive adjudication process, which is unlikely to be concluded in the foreseeable future.

As of December 31, 2007, the Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represented approximately 50 percent of all of Avista Corp.'s employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expires in March 2009. Three local agreements in Oregon, which cover approximately 50 employees, expire in April 2010.

NOTE 25: POTENTIAL HOLDING COMPANY FORMATION

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

Avista Corp. received approval from the FERC in April 2006 (conditioned on approval by the state regulatory agencies), the IPUC in June 2006 and the WUTC in February 2007. Avista Corp. has also filed for approval from the utility regulators in Oregon and Montana and proceedings are pending in each of these jurisdictions. The statutory share exchange is subject to the receipt of the remaining regulatory approvals and the satisfaction of other conditions. If the statutory share exchange and the implementation of the holding company structure are approved by regulators on terms acceptable to the Company, it may be completed sometime in 2008.

The IPUC accepted a stipulation entered into between Avista Corp. and the IPUC Staff that sets forth a variety of conditions, which would serve to segregate the Company's utility operations from the other businesses conducted by the holding company. The stipulation would require Avista Corp. to maintain certain common equity levels as part of its capital structure. Avista Corp. committed to increase its actual utility common equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008, which is consistent with provisions of the Company's Washington general rate case implemented on January 1, 2006. The calculation of the utility equity component is essentially the ratio of Avista Corp.'s total common equity to total capitalization excluding, in each case, Avista Corp.'s investment in Avista Capital. The utility equity component was approximately 45 percent as of December 31, 2007. In addition, IPUC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 25 percent of total capitalization which, for this purpose, includes long and short-term debt, capitalized lease obligations and preferred and common equity.

The WUTC accepted a similar stipulation entered into between Avista Corp. and the WUTC staff. The stipulation requires Avista Corp. to increase its actual utility common equity component to 40 percent by June 30, 2008. In addition, WUTC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 30 percent of total capitalization.

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

NOTE 26. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2012. Total payments under these contracts were $15.4 million in 2007, $12.5 million in 2006 and $12.8 million in 2005. The majority of the costs are included in operation expenses in the Statements of Income. Minimum contractual obligations under the Company's information services contracts are $14.7 million in 2008, $15.1 million in 2009, $15.4 million in 2010, $14.5 million in 2011 and $14.5 million in 2012. The largest of these contracts provides for increases due to changes in the cost of living index and further provides flexibility in the annual obligation from year-to-year subject to a three-year true-up cycle.

NOTE 27. PRIOR PERIOD ADJUSTMENT

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

The prior period adjustments decreased retained earnings by $2.5 million.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2007

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Intangible Plant**			
3				
4	301 Organization			
5	302 Franchises & Consents	6,222,448	6,222,448	
6	303 Miscellaneous Intangible Plant	(20,531)	(20,531)	
7				
8	**TOTAL Intangible Plant**	6,201,917	6,201,917	
9				
10	**Production Plant**			
11				
12	Steam Production			
13				
14	310 Land & Land Rights	1,296,911	1,291,607	0%
15	311 Structures & Improvements	99,987,414	99,970,611	0%
16	312 Boiler Plant Equipment	121,837,148	121,320,039	0%
17	313 Engines & Engine Driven Generators			
18	314 Turbogenerator Units	33,989,562	34,799,911	-2%
19	315 Accessory Electric Equipment	15,999,915	16,066,058	0%
20	316 Miscellaneous Power Plant Equipment	12,912,553	12,951,363	0%
21	317 Asset Retirement Costs	134,589	134,589	
22	**TOTAL Steam Production Plant**	286,158,092	286,534,178	0%
23				
24	Nuclear Production			
25				
26	320 Land & Land Rights			
27	321 Structures & Improvements			
28	322 Reactor Plant Equipment			
29	323 Turbogenerator Units			
30	324 Accessory Electric Equipment			
31	325 Miscellaneous Power Plant Equipment			
32				
33	**TOTAL Nuclear Production Plant**			
34				
35	Hydraulic Production			
36				
37	330 Land & Land Rights	42,413,876	42,652,083	-1%
38	331 Structures & Improvements	12,411,466	13,330,502	-7%
39	332 Reservoirs, Dams & Waterways	33,001,627	33,179,949	-1%
40	333 Water Wheels, Turbines & Generators	33,266,432	40,550,212	-18%
41	334 Accessory Electric Equipment	12,990,599	13,001,156	0%
42	335 Miscellaneous Power Plant Equipment	2,775,435	2,665,428	4%
43	336 Roads, Railroads & Bridges	225,369	225,369	
44				
45	**TOTAL Hydraulic Production Plant**	137,084,804	145,604,699	-6%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2007

	Account Number & Title		Last Year	This Year	% Change
1					
2		Production Plant (cont.)			
3					
4	Other Production				
5					
6	340	Land & Land Rights			
7	341	Structures & Improvements			
8	342	Fuel Holders, Producers & Accessories			
9	343	Prime Movers			
10	344	Generators			
11	345	Accessory Electric Equipment			
12	346	Miscellaneous Power Plant Equipment			
13					
14		**TOTAL Other Production Plant**			
15					
16		**TOTAL Production Plant**	423,242,896	432,138,877	-2%
17					
18		**Transmission Plant**			
19					
20	350	Land & Land Rights	883,384	883,384	
21	352	Structures & Improvements	461,581	477,507	-3%
22	353	Station Equipment	16,479,010	16,465,350	0%
23	354	Towers & Fixtures	16,013,530	16,024,245	0%
24	355	Poles & Fixtures	7,173,299	7,173,570	0%
25	356	Overhead Conductors & Devices	15,745,311	15,746,564	0%
26	357	Underground Conduit			
27	358	Underground Conductors & Devices			
28	359	Roads & Trails	367,476	367,476	
29					
30		**TOTAL Transmission Plant**	57,123,591	57,138,096	0%
31					
32		**Distribution Plant**			
33					
34	360	Land & Land Rights			
35	361	Structures & Improvements	15,881	15,881	
36	362	Station Equipment	152,268	152,268	
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	10,080	10,080	
39	365	Overhead Conductors & Devices	6,676	6,676	
40	366	Underground Conduit	46	46	
41	367	Underground Conductors & Devices	637	637	
42	368	Line Transformers	897	897	
43	369	Services	127	127	
44	370	Meters	29	29	
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49		**TOTAL Distribution Plant**	186,641	186,641	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2007

	Account Number & Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment	174,931	192,433	-9%
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment	34,660	35,726	-3%
12	397 Communication Equipment	24,007	691,266	-97%
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	233,598	919,425	
17				
18	**TOTAL Electric Plant in Service**	486,988,643	496,584,956	

MONTANA DEPRECIATION SUMMARY

Year: 2007

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production	286,534,178	173,627,659	178,220,649	N/A
3	Nuclear Production				
4	Hydraulic Production	145,604,699	17,131,668	17,673,936	N/A
5	Other Production				
6	Transmission	57,138,096	20,191,315	18,543,451	N/A
7	Distribution	186,641	57,488	56,896	N/A
8	General		1,414,499	1,576,205	N/A
9	**TOTAL**	489,463,614	212,422,629	216,071,137	

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account		Last Year Bal.	This Year Bal.	%Change
1					
2	151	Fuel Stock	694,391	696,214	0%
3	152	Fuel Stock Expenses Undistributed			
4	153	Residuals			
5	154	Plant Materials & Operating Supplies:			
6		Assigned to Construction (Estimated)			
7		Assigned to Operations & Maintenance			
8		Production Plant (Estimated)	1,645,850	1,721,978	-4%
9		Transmission Plant (Estimated)			
10		Distribution Plant (Estimated)			
11		Assigned to Other			
12	155	Merchandise			
13	156	Other Materials & Supplies			
14	157	Nuclear Materials Held for Sale			
15	163	Stores Expense Undistributed			
16					
17	**TOTAL Materials & Supplies**		2,340,241	2,418,192	-3%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent	% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number			
2	Order Number			
3		**Reference is made to Schedule 27**		
4	Common Equity			
5	Preferred Stock			
6	Long Term Debt			
7	Other			
8	**TOTAL**			
9				
10	Actual at Year End			
11				
12	Common Equity			
13	Preferred Stock			
14	Long Term Debt			
15	Other			
16	**TOTAL**			

STATEMENT OF CASH FLOWS

Year: 2007

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	73,132,859	38,475,085	90%
6	Depreciation	84,354,287	88,540,958	-5%
7	Amortization	66,518,167	28,425,416	134%
8	Deferred Income Taxes - Net	(16,465,046)	4,003,423	-511%
9	Investment Tax Credit Adjustments - Net	(49,308)	(49,308)	
10	Change in Operating Receivables - Net	11,519,009	1,881,714	512%
11	Change in Materials, Supplies & Inventories - Net	203,045	(3,940,327)	105%
12	Change in Operating Payables & Accrued Liabilities - Net	(8,118,183)	(28,529,359)	72%
13	Allowance for Funds Used During Construction (AFUDC)	(2,429,542)	(4,736,330)	49%
14	Change in Other Assets & Liabilities - Net	(15,949,173)	(11,056,553)	-44%
15	Other Operating Activities (explained on attached page)	(19,773,577)	9,584,545	-306%
16	**Net Cash Provided by/(Used in) Operating Activities**	172,942,538	122,599,264	41%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(156,952,633)	(196,772,585)	20%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	657,770		#DIV/0!
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates	36,646,304	170,364,287	-78%
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	4,735,719	(2,924,658)	262%
27	**Net Cash Provided by/(Used in) Investing Activities**	(114,912,840)	(29,332,956)	-292%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	149,778,000		#DIV/0!
32	Preferred Stock			
33	Common Stock	88,393,784	4,977,331	1676%
34	Long-Term Debt to Affiliated Trusts			
35	Net Increase in Short-Term Debt			
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(197,231,550)	(26,156,580)	-654%
39	Preferred Stock	(1,750,000)	(26,250,000)	93%
40	Common Stock			
41	Long-Term Debt to Affiliated Trusts			
42	Net Decrease in Short-Term Debt	(59,000,000)	(4,000,000)	-1375%
43	Dividends on Preferred Stock			
44	Dividends on Common Stock	(27,927,206)	(31,450,517)	11%
45	Other Financing Activities (explained on attached page)	(9,599,614)	(164,700)	-5729%
46	**Net Cash Provided by (Used in) Financing Activities**	(57,336,586)	(83,044,466)	31%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	693,112	10,221,842	-93%
49	**Cash and Cash Equivalents at Beginning of Year**	(2,363,195)	(1,670,083)	-42%
50	**Cash and Cash Equivalents at End of Year**	(1,670,083)	8,551,759	-120%

Company Name: **Avista Corp.** **SCHEDULE 23A**

STATEMENT OF CASH FLOWS

Year: 2007

	Description	Last Year	This Year	% Change
1	**Detail of Lines 15, 26 and 45**			
2	**Line 15: Other Operating Activities**			
	Regulatory disallowance of debt repurchase costs		3,849,725	
	Write-down of asset		2,289,978	
3	Gain on disposition of property	(99,559)		
4	ESOP Dividends	415,596	1,045	
5	Change in allowance for uncollectible receivables	(497,564)	235,324	-311%
6	Regulatory Gas Cost and Power Cost Adjustment	(6,497,199)	(3,898,852)	-67%
7	Non-cash stock compensation	3,744,610	2,511,576	
8	Subsidiary earnings	(16,839,461)	4,595,749	-466%
9	Total Line 15	(19,773,577)	9,584,545	-306%
10				
11	**Line 26: Other Investing Activities**			
	Proceeds from sale of utility property claim	5,483,780		
	Changes in other property and investments	(763,324)	(2,942,625)	
12	Notes receivable	15,263	17,967	
13	Total Line 26	4,735,719	(2,924,658)	
10	**Line 45: Other Financing Activities**			
	Cash received (paid) in interest rate swap agreement	(3,738,000)		
11	Premiums paid for repurchase of debt	(425,996)		
12	Debt Issuance costs	(5,435,618)	(164,700)	
13	Total Line 45	(9,599,614)	(164,700)	

LONG TERM DEBT

Year: 2007

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1									
2	Medium-Term Notes								
3	Series A	various	various	250,000,000	248,374,625	68,000,000	8.20%	5,573,738	8.20%
4	Series B	various	various	161,000,000	160,141,500	5,000,000	6.98%	371,012	7.42%
5	Series C	various	various	109,000,000	108,272,250	75,000,000	6.62%	4,961,596	6.62%
6									
7	Pollution Control Bonds								
8	Colstrip 1999A (1)	9/1/99	10/1/32	66,700,000	59,343,493	66,700,000	5.26%	3,663,292	5.49%
9	Colstrip 1999B (1)	9/1/99	3/1/34	17,000,000	14,875,407	17,000,000	5.49%	972,776	5.72%
10	6% Pollution Control Bonds	7/1/93	12/1/23	4,100,000	2,838,725	4,100,000	6.23%	386,159	9.42%
11									
12	(1) These Secured Pollution Control Bonds are subject to remarketing on December 30, 2008. These bonds are included in the current portion of								
13	long-term debt because they are puttable at the option of the security holders on that date.								
14	If the bonds cannot be successfully remarketed on that date, the Company will be required to purchase the outstanding bonds.								
15									
16	First Mortgage Bonds								
17	6.125% Issued September 2003	9/1/03	9/1/13	45,000,000	44,795,250	45,000,000	6.63%	2,982,714	6.63%
18	5.45% Issued November 2004	11/18/04	12/1/19	90,000,000	88,975,000	90,000,000	5.59%	5,033,114	5.59%
19	6.25% Issued Nov/Dec 2005	11/17/05	12/1/35	150,000,000	147,937,500	150,000,000	6.36%	9,538,208	6.36%
20	5.70% Issued Dec 2006	12/15/06	7/1/37	150,000,000	145,687,500	150,000,000	5.93%	8,900,675	5.93%
21									
22	Senior Notes	4/3/01	6/1/08	400,000,000	392,000,000	272,860,000	10.34%	28,213,716	10.34%
###									
24	Junior Subordinated Debentures	4/5/04	4/1/34	61,856,000	53,109,004	61,856,000	7.46%	4,478,559	7.24%
25	Junior Subordinated Debentures	6/3/97	6/1/37	51,547,000	36,828,822	51,547,000	6.70%	2,612,260	5.07%
26									
27	Committed line of credit	12/19/04	4/1/11	320,000,000				794,332	
28	Total cost includes commitment fees								
29									
30									
31									
32	**TOTAL**			1,876,203,000	1,503,179,076	1,057,063,000		78,482,151	7.42%

PREFERRED STOCK

Year: 2007

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2										
3	All preferred stock redeemed in 2007.									
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
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17										
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21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2007

		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
1									
2									
3									
4	January								
5									
6	February								
7									
8	March	52,683,897	17.59	0.26	0.145		25.81	22.91	
9									
10	April								
11									
12	May								
13									
14	June	52,775,193	17.54	0.26	0.150		24.89	21.17	
15									
16	July								
17									
18	August								
19									
20	September	52,833,925	17.27	(0.07)	0.150		22.38	18.19	
21									
22	October								
23									
24	November								
25									
26	December	52,877,380	17.27	0.26	0.150		22.24	19.58	
27									
28									
29									
30									
31									
32	TOTAL Year End	52,796,318	17.27	0.72	0.595	17.36%	21.54		29.9

MONTANA EARNED RATE OF RETURN

Year: 2007

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service			
3	108 (Less) Accumulated Depreciation			
4	**NET Plant in Service**			
5				
6	Additions			
7	154, 156 Materials & Supplies			
8	165 Prepayments			
9	Other Additions			
10	**TOTAL Additions**			
11				
12	Deductions			
13	190 Accumulated Deferred Income Taxes			
14	252 Customer Advances for Construction			
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions			
17	**TOTAL Deductions**			
18	**TOTAL Rate Base**			
19				
20	**Net Earnings**			
21				
22	**Rate of Return on Average Rate Base**			
23				
24	**Rate of Return on Average Equity**			
25				
26	Major Normalizing Adjustments & Commission			
27	Ratemaking adjustments to Utility Operations			
28				
29				
30	**Rates charged were based on the**			
31	**Company's last rate order from the Idaho**			
32	**Public Utilities Commission and accepted by**			
33	**the Montana Commission. The Company**			
34	**does not calculate separate rates of return**			
35	**for the Montana jurisdiction.**			
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	**Adjusted Rate of Return on Average Rate Base**			
48				
49	**Adjusted Rate of Return on Average Equity**			

MONTANA COMPOSITE STATISTICS

Year: 2007

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	496,585
5	107	Construction Work in Progress	
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	2,418
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(216,071)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	282,932
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	14,846
18			
19	403 - 407	Depreciation & Amortization Expenses	11,413
20		Federal & State Income Taxes	507
21		Other Taxes	7,282
22		Other Operating Expenses	29,248
23		TOTAL Operating Expenses	48,451
24			
25		Net Operating Income	(33,605)
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	(33,605)
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	10
36		Commercial	1
37		Industrial	
38		Other	8
39			
40		**TOTAL NUMBER OF CUSTOMERS**	19
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	15,000
45		Average Annual Residential Cost per (Kwh) (Cents) *	4.55
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	56.82
48		Gross Plant per Customer	49,658

MONTANA CUSTOMER INFORMATION

Year: 2007

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1						
2	Noxon, Montana		10	1	8	19
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
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26						
27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**		10	1	8	19

MONTANA EMPLOYEE COUNTS

Year: 2007

	Department	Year Beginning	Year End	Average
1				
2	Noxon Generating Station	32	32	32
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
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37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**	32	32	32

Company Name: Avista Corporation **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2007

	Project Description	Total Company	Total Montana
1			
2	Noxon Rapids Capital Projects Upgrades	12,652,495	12,652,495
3			
4	Clark Fork Improvement	1,989,707	1,989,707
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
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39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**	14,642,202	14,642,202

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2007

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	12	800	1685	1,135,138	173,913
2	Feb.	1	1900	1512	984,749	187,615
3	Mar.	2	800	1452	1,072,376	295,568
4	Apr.	2	1000	1301	1,048,984	327,921
5	May	31	1700	1242	1,097,282	377,603
6	Jun.	20	1700	1318	1,039,192	332,215
7	Jul.	13	1400	1629	1,024,840	169,481
8	Aug.	2	1700	1519	918,583	131,028
9	Sep.	4	1700	1270	838,879	132,105
10	Oct.	31	800	1361	872,747	114,257
11	Nov.	28	1800	1529	959,467	134,000
12	Dec.	12	1800	1595	1,098,331	160,397
13	**TOTAL**				12,090,568	2,536,103

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.					
15	Feb.					
16	Mar.		Information is not available by state			
17	Apr.					
18	May					
19	Jun.					
20	Jul.					
21	Aug.					
22	Sep.					
23	Oct.					
24	Nov.					
25	Dec.					
26	**TOTAL**					

TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,972,174	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	8,924,726
4	Hydro - Conventional	3,688,791		
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	1,668,093	for Resale	2,536,103
7	(Less) Energy for Pumping			
8	**NET Generation**	7,329,058	Non-Requirements Sales	
9	Purchases	4,761,534	for Resale	
10	Power Exchanges			
11	Received	974,470	Energy Furnished	
12	Delivered	(974,494)	Without Charge	
13	**NET Exchanges**	(24)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	3,553,693	Electric Utility	12,302
16	Delivered	(3,553,693)		
17	**NET Transmission Wheeling**		Total Energy Losses	617,437
18	Transmission by Others Losses			
19	**TOTAL**	12,090,568	**TOTAL**	12,090,568

SOURCES OF ELECTRIC SUPPLY

Year: 2007

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1					
2	Washington:				
3					
4	Thermal	Kettle Falls	Kettle Falls, WA	52	299,413
5	Hydro	Little Falls	Ford, WA	37	192,921
6	Hydro	Long Lake	Ford, WA	90	471,412
7	Hydro	Monroe Street	Spokane, WA	16	100,338
8	Hydro	Nine Mile	Spokane, WA	20	99,421
9	Hydro	Upper Falls	Spokane, WA	11	62,668
10	Combustion -				
11	Turbine	Northeast	Spokane, WA	57	2,308
12	Combustion -				
13	Turbine	Kettle Falls Bi-fuel	Kettle Falls, WA	8	1,466
14	Combustion -				
15	Turbine	Boulder Park	Spokane, WA	25	23,313
16					
17					
18	Idaho:				
19	Hydro	Cabinet Gorge	Clark Fork, ID	261	1,088,206
20	Hydro	Post Falls	Post Falls, ID	18	83,374
21	Combustion -				
22	Turbine	Rathdrum	Rathdrum, ID	161	18,228
23					
24					
25					
26	Montana:				
27	Thermal	Colstrip #3 and #4	Colstrip, MT	226	1,672,761
28	Hydro	Noxon	Thompson Falls, MT	445	1,590,451
29					
30	Oregon:				
31	Combustion -				
32	Turbine	Coyote Springs 2	Boardman, OR	306	1,622,778
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	**Total**			1,733	7,329,058

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2007

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1							
2							
3	Not applicable						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**						

Electric Universal System Benefits Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2						
3	Avista Corp. does not have any benefit programs in Montana.					
4						
5						
6						
7						
8	Market Transformation					
9						
10						
11						
12						
13						
14						
15	Renewable Resources					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Large Customer Self Directed					
36						
37						
38						
39						
40						
41						
42	Total					

43	Number of customers that received low income rate discounts	
44	Average monthly bill discount amount ($/mo)	
45	Average LIEAP-eligible household income	
46	Number of customers that received weatherization assistance	
47	Expected average annual bill savings from weatherization	
48	Number of residential audits performed	

Montana Conservation & Demand Side Management Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2						
3	Avista Corp. does not have any conservation & demand side management programs in Montana.					
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Other					
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46	Total					

MONTANA CONSUMPTION AND REVENUES

Year: 2007

	Sales of Electricity	Operating Revenues		MegaWatt Hours Sold		Avg. No. of Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$6,818	$7,147	150	158	10	11
2	Commercial - Small	2,152	2,223	33	34	1	1
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large						
6	Interruptible Industrial						
7	Public Street & Highway Lighting						
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities						
11	Interdepartmental	7,665	7,445	122	115	8	7
12							
13	**TOTAL**	$16,635	$16,815	305	307	19	19