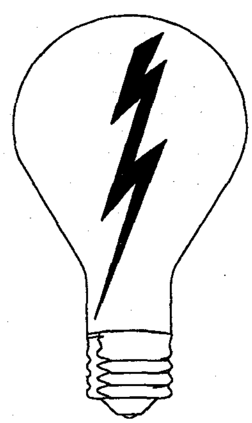
YEAR 1994

ANNUAL REPORT

OF

The Washington Water Power Company

ELECTRIC UTILITY



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

Revised November 9, 1994

Electric Annual Report

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Sch. 1 — IDENTIFICATION

Legal Name of Respondent:	The Washington Water Power Company
Name Under Which Respondent Does Business:	The Washington Water Power Company
Date Utility Service First Offered in Montana:	July, 1960
Person Responsible for Report:	J.E. Eliassen, Vice President-Finance & CFO
Telephone Number for Inquiries:	(509) 482-4335
Address for Correspondence Concerning Report:	East 1411 Mission Avenue Spokane, WA 99202

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity:

Sch. 2 — BOARD OF DIRECTORS

	Director Name & Address (City, State)		Remuneration
1	Paul A. Redmond (1)	E. 1411 Mission Avenue, Spokane, WA 99202	498,742
2	David A. Clack	E. 325 Sprague Avenue, Spokane, WA 99202	36,773
3	Duane B. Hagadone	P.O.Box 6200, Coeur d' Alene, ID 83816	37,711
4	Robert S. Jepson	1 Skidway Village Walk, Suite 201, Savanna, GA 31411	50,798
5	Eugene B. Meyer	3 Plumbridge Lane, Hilton Head Island, SC 29928	51,584
6	General H. Norman Schwarzkopf	400 N. Ashley Street, Suite 3050, Tampa, FL 33602	38,045
7	B. Jean Silver	N. 7102 Audubon Drive, Spokane, WA 99208	40,288
8	Larry A. Stanley	W. 311 32nd Avenue, Spokane, WA 99203	40,606
9	R. John Taylor	P.O. Box 538, Lewiston ID 83501	44,617
10	Eugene Thompson	3307 Pinecrest Road, Moscow, ID 83843	39,590
11			
12			
13	(1) Mr Redmond is Chairman of the Board, President and Chief Executive Officer.		
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24			

Sch. 3	OFFICERS		
	Title	Department Supervised	Name
1	Chairman of the Board, President and	*	Paul A. Redmond
2	Chief Executive Officer		
4	Vice President-Finance and Chief	Finance Department	J. E. Eliassen
5	Financial Officer		
7	Senior Vice President	Rates and Resourses	W. L. Bryan
9	Vice President	Marketing, Public Relations	J. G. Matthisen
11	Vice President	Corporate Services, Human Resourses	R. D. Fukai
13	Vice President	Operations	N. J. Racicot
15	Treasurer	Funds Management, Tax and Payroll,	R. R. Peterson
16		Corporate Finance and Investor Relations	
18	Controller	Corporate Accounting, Plant Accounting,	J. W. Buergel
19		Rates	
21	Corporate Secretary	Shareholder Services	T. L. Syms

Sch. 4

CORPORATE STRUCTURE

Subsidiary/Company Name	Line of Business	Earnings	% of Total
Pentzer Corporation	Parent Company of all of the Company's Subsideries, except Washington Irrigation and Development Company and WP Finance	13,515,283	99.2
Washington Irrigation and Development Company	Non-Operating	48,908	0.4
Limestone	Non-Operating	65,577	0.5
		13,629,768	100.0

Sch. 5

CORPORATE ALLOCATIONS

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1						
2	Not Applicable					
3						
4						
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32						
33						
34						
35	TOTAL					

Sch. 6 **AFFILIATE TRANSACTIONS - PRODUCTS AND SERVICES PROVIDED TO UTILITY**

	Affiliate Name	Products and Services	Methods to Determine Price	Charges to Utility	% Total Affil. Revs.	Charges to MT Utility
1						
2	Not Applicable					
3						
4						
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Sch. 7 **AFFILIATE TRANSACTIONS - PRODUCTS AND SERVICES PROVIDED BY UTILITY**

	Affiliate Name	Products and Services	Methods to Determine Price	Charges to Utility	% Total Affil. Revs.	Charges to MT Utility
1						
2	Not Applicable					
3						
4						
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Sch. 8	MONTANA UTILITY INCOME STATEMENT				
		Account Number & Title	Last Year	This Year	% Change
1	400	Operating Revenues	3,144,590	5,294,164	68.36
2					
3		Operating Expenses			
4	401	Operating Expenses	29,427,170	39,282,247	33.49
5	402	Maintenance	6,151,124	5,268,949	(14.34)
6	403	Depreciation Expense	8,558,453	8,503,523	(0.64)
7	404-405	Amortization of Electric Plant	None or not allocated		
8	406	Amort. of Plant Acquisition Adjustments	None or not allocated		
9	407	Amort. of Property Losses, unrecovered Plant &			
10		Regulatory Study Costs			
11	408.1	Taxes Other Than Income	9,108,557	8,884,963	(2.45)
12	409.1	Income Taxes - Federal	None or not allocated		
13		- Other (State of Montana)	667,886	802,078	20.09
14	410.1	Provision for Deferred Income Taxes	None or not allocated		
15	411.1	(Less) Provision for Def. Inc. Taxes - Credit	None or not allocated		
16	411.4	Investment Tax Credit Adjustment	None or not allocated		
17	411.6	(Less) Gains from Disposition of Utility Plant	None or not allocated		
18	411.7	Losses from Disposition of Utility Plant	None or not allocated		
19					
20		TOTAL Utility Operating Expenses	53,913,190	62,741,760	16.38
21					
22		NET UTILITY OPERATING INCOME	(50,768,600)	(57,447,596)	(13.16)

Sch. 9	MONTANA REVENUES				
		Account Number and Title	Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	10,243	7,696	(24.87)
3	442	Commercial & Industrial - Small	2,493	1,424	(42.88)
4		Commercial & Industrial - Large			
5	444	Public Street & Highway Lighting			
6	445	Sales Other Public Authorities			
7	446	Sales to Railroads & Railways			
8	448	Interdepartmental Sales	234	4,222	100.00
9					
10		TOTAL Sales of Electricity	12,970	13,342	2.87
11	447	Sales for Resale	1,387,834	1,410,623	1.64
12					
13		TOTAL Sales to Ultimate Consumers	1,400,804	1,423,965	1.65
14	449.1	(Less) Provision for Rate Refunds			
15					
16		TOTAL Revenue Net of Provision for Refunds	1,400,804	1,423,965	1.65
17		Other Operating Revenue			
18	450	Forfeited Discounts & Late Payment Revenues			
19	451	Miscellaneous Service Revenues			
20	453	Sales of Water & Water Power	9,158	4,629	(49.45)
21	454	Rent for Electric Property	101,675	60,865	(40.14)
22	455	Interdepartmental Rents			
23	456	Other Electric Revenues	1,632,953	3,804,705	133.00
24					
25		TOTAL Other Operating Revenues	1,743,786	3,870,199	121.94
26					
27		Total Electric Operating Revenue	3,144,590	5,294,164	68.36

	Account Number & Title	Last Year	This Year	% Change
1	**Power Production Expenses**			
2				
3	**Steam Power Generation**			
4	Operation			
5	(500) Operation Supervision and Engineering	329,265	394,167	19.71
6	(501) Fuel	10,056,035	13,297,936	32.24
7	(502) Steam Expenses	1,221,504	1,332,230	9.06
8	(503) Steam from Other Sources	0	4,687	100.00
9	(Less) Steam Transferred-Cr.	0	0	
10	(505) Electric Expenses	483,286	503,210	4.12
11	(506) Miscellaneous Steam Power Expenses	2,004,889	1,186,977	(40.80)
12	(507) Rents	6,521	1,605	(75.39)
13				
14	TOTAL Operation - Steam	14,101,500	16,720,812	18.57
15				
16	Maintenance			
17	(510) Maintenance Supervision and Engineering	389,263	479,475	23.18
18	(511) Maintenance of Structures	351,984	354,734	0.78
19	(512) Maintenance of Boiler Plant	2,780,439	2,603,804	(6.35)
20	(513) Maintenance of Electric Plant	1,652,437	598,462	(63.78)
21	(514) Maintenance of Miscellaneous Steam Plant	389,267	517,900	33.04
22				
23	TOTAL Maintenance - Steam	5,563,390	4,554,375	(18.14)
24				
25	TOTAL Power Production Expenses-Steam Plant	19,664,890	21,275,187	8.19
26				
27	**Nuclear Power Generation**			
28	Operation			
29	(517) Operation Supervision and Engineering			
30	(518) Fuel			
31	(519) Coolants and Water			
32	(520) Steam Expenses			
33	(521) Steam from Other Sources			
34	(Less) (522) Steam Transferred-Cr.			
35	(523) Electric Expenses			
36	(524) Miscellaneous Nuclear Power Expenses			
37	(525) Rents			
38				
39	TOTAL Operation Nuclear	0	0	
40				
41	Maintenance			
42	(528) Maintenance Supervision and 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	0	0	
49				
50	TOTAL Power Production Expenses-Nuclear Power	0	0	

	Account Number and Title	Last Year	This Year	% Change
1	**Power Production Expenses - continued**			
2	**Hydraulic Power Generation**			
3	Operation			
4	(535) Operation Supervision and Engineering	58,986	28,660	(51.41)
5	(536) Water for Power			
6	(537) Hydraulic Expenses	7,851	103,936	1,223.86
7	(538) Electric Expenses	458,489	470,107	2.53
8	(539) Miscellaneous Hydraulic Power Generation Expenses	81,612	73,654	(9.75)
9	(540) Rents	48	110	129.17
10				
11	TOTAL Operation - Hydraulic	606,986	676,467	11.45
12				
13	Maintenance			
14	(541) Maintenance Supervision and Engineering	5,796	1,843	(68.20)
15	(542) Maintenance of Structures	44,005	66,058	50.11
16	(543) Maintenance of Reservoirs, Dams, and Waterways	18,561	155,201	736.17
17	(544) Maintenance of Electric Plant	380,113	359,735	(5.36)
18	(545) Maintenance of Miscellaneous Hydraulic Plant	17,308	9,256	(46.52)
19				
20	TOTAL Maintenance - Hydraulic	465,783	592,093	27.12
21				
22	TOTAL Hydraulic Power Production Expenses	1,072,769	1,268,560	18.25
23				
24	**Other Power Generation**			
25	Operation			
26	(546) Operation Supervision and Engineering			
27	(547) Fuel			
28	(548) Generation Expenses			
29	(549) Miscellaneous Other Power Generation Expenses			
30	(550) Rents			
31				
32	TOTAL Operation - Other	0	0	
33				
34	Maintenance			
35	(551) Maintenance Supervision and Engineering	0	0	
36	(552) Maintenance of Structures			
37	(553) Maintenance of Generating and Electric Plant			
38	(554) Maintenance of Miscellaneous Other Power Generation Plant			
39				
40	TOTAL Maintenance - Other	0	0	
41				
42	TOTAL Power Production Expenses-Other Power	0	0	
43				
44	**Other Power Supply Expenses**			
45	(555) Purchased Power	13,628,419	21,232,300	55.79
46	(556) System Control and Load Dispatching			
47	(557) Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	13,628,419	21,232,300	55.79
50				
51	**TOTAL Power Production Expenses**	34,366,078	43,776,047	27.38

	Account Number & Title	LastYear	This Year	% Change
1	**Transmission Expenses**			
2	Operation			
3	(560) Operation Supervision and Engineering	22,400	24,461	9.20
4	(561) Load Dispatching	23,448	27,197	15.99
5	(562) Station Expenses	80,625	89,218	10.66
6	(563) Overhead Line Expenses	7,276	24,881	241.96
7	(564) Underground Line Expenses			
8	(565) Transmission of Electricity by Others	12	119,241	9,935.75
9	(566) Miscellaneous Transmission Expenses		141	100.00
10	(567) Rents	101,433	79,059	(22.06)
11				
12	TOTAL Operation - Transmission	235,194	364,198	54.85
13	Maintenance			
14	(568) Maintenance Supervision and Engineering	6,544	6,015	(8.08)
15	(569) Maintenance of Structures	(12)	(16)	33.33
16	(570) Maintenance of Station Equipment	45,770	35,071	(23.38)
17	(571) Maintenance of Overhead Lines	18,341	22,133	20.67
18	(572) Maintenance of Underground Lines			
19	(573) Maintenance of Miscellaneous Transmission Plant			
20				
21	TOTAL Maintenance - Transmission	70,643	63,203	(10.53)
22				
23	**TOTAL Transmission Expenses**	305,837	427,401	39.75
24				
25	**Distributon Expenses**			
26	Operation			
27	(580) Operation Supervision and Engineering			
28	(581) Load Dispatching			
29	(582) Station Expenses	700	0	(100.00)
30	(583) Overhead Line Expenses	150	0	(100.00)
31	(584) Underground Line Expenses		160	100.00
32	(585) Street Lighting and Signal System Expenses	61	0	(100.00)
33	(586) Meter Expenses			
34	(587) Customer Installations Expenses		113	100.00
35	(588) Miscellaneous Distribution Expenses			
36	(589) Rents		12	
37				
38	TOTAL Operation - Distribution	911	285	(68.72)
39	Maintenance			
40	(590) Maintenance Supervision and Engineering			
41	(591) Maintenance of Structures			
42	(592) Maintenance of Station Equipment	727	6	(99.17)
43	(593) Maintenance of Overhead Lines	819	1,021	24.66
44	(594) Maintenance of Underground Lines		731	100.00
45	(595) Maintenance of Line Transformers			
46	(596) Maintenance of Street Lighting and Signal Systems			
47	(597) Maintenance of Meters	0	0	
48	(598) Maintenance of Miscellaneous Distribution Plant			
49				
50	TOTAL Maintenance - Distribution	1,546	1,758	13.71
51				
52	**TOTAL Distribution Expenses**	2,457	2,043	(16.85)

	Account Number & Title	Last Year	This Year	% Change
1	**Customer Accounts Expense**			
2	Operation			
3	(901) Supervision			
4	(902) Meter Reading Expenses			
5	(903) Customer Records and Collection Expenses		28	100.00
6	(904) Uncollectible Accounts			
7	(905) Miscellaneous Customer Accounts Expenses			
8				
9	**TOTAL Customer Accounts Expenses**	0	28	100.00
10				
11	**Customer Service & Info Expense**			
12	Operation			
13	(907) Supervision			
14	(908) Customer Assistance Expenses			
15	(909) Informational and Instructional Expenses			
16	(910) Miscellaneous Customer Service and Informational Expenses			
17				
18	**TOTAL Cust. Service and Informational Expenses**	0	0	
19				
20	**Sales Expense**			
21	Operation			
22	(911) Supervision			
23	(912) Demonstrating and Selling Expenses			
24	(913) Advertising Expenses			
25	(916) Miscellaneous Sales Expenses			
26				
27	**TOTAL Sales Expenses**	0	0	
28				
29	**Administrative & General Expense**			
30	Operation			
31	(920) Administrative and General Salaries			
32	(921) Office Supplies and Expenses	494	1,946	293.93
33	(Less) (922) Administrative expenses Transferred-Credit			
34	(923) Outside Services Employed			
35	(924) Property Insurance	75,216	99,718	32.58
36	(925) Injuries and Damages	35,411	23,054	(34.90)
37	(926) Employee Pensions and Benefits	655	5,697	769.77
38	(927) Franchise Requirements			
39	(928) Regulatory Commission Expenses	742,342	457,742	(38.34)
40	(Less) (929) Duplicate Charges-Cr.			
41	(930.1) General Advertising Expenses			
42	(930.2) Miscellaneous General Expenses	42	0	(100.00)
43	(931) Rents			
44				
45	TOTAL Operation	854,160	588,157	(31.14)
46	Maintenance			
47	(935) Maintenance of General Plant	49,762	57,520	15.59
48				
49	TOTAL Administrative and General Expenses	903,922	645,677	(28.57)
50				
51	**TOTAL Electric Operation and Maintenance Expenses**	35,578,294	44,851,196	26.06

Sch. 11 MONTANA TAXES OTHER THAN INCOME

Line	Description of Tax	Last Year	This Year	% Change
2	Real and Personal Property Tax	8,520,496	8,349,506	(2.01)
4	Beneficial Use Tax	0	0	0
6	Kilowatt Hour Tax	582,584	531,594	(8.75)
8	Unemployment Tax	4,168	4,095	(1.75)
10	Consumer Council Tax	1,266	(264)	(120.85)
12	Public Commission Tax	43	32	(25.58)
53	TOTAL MT Taxes other than Income	9,108,557	8,884,963	(2.45)

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES				
	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1					
2					
3	See Schedule pages 13A-13H following.				
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53	TOTAL Payments for Services				

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1995	Dec. 31, 1994

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. (These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual [other than for services as an employee or for payments made for medical and related services] amounting to more than $25,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political and Related Activities.

(a) Name and address of person or organization rendering serives.

(b) description of services reveived during year and project of case to which services relate,

(c) basis of charges,

(d) total charges for the year, detailing utility department and account charged.

2. For any services which are of a continuing nature, give the date and term of contract and date of Commission authorization, if contract received Commission approval.

3. Designate with an asterisk associated companies.

(a) Acres International Corporation			
10201 Southport Road SW	(c)	Operating	$19,937
5th Floor		Capital	$25,568
Calgary, AB CANADA T2W4X9		Other	
(b) Consulting Engineers		Total	$45,505
(a) ADP Proxy Solicitation			
	(c)	Operating	$32,283
PO Box 12298		Capital	
Newark, NJ 07101-5298		Other	$3,150
(b) Proxy Solicitation		Total	$35,433
(a) Bartlit, Beck, Herman, Palenchar & Scott			
Courthouse PL	(c)	Operating	$39,052
54 W. Hubbard Street		Capital	
Chicago, IL 60610		Other	
(b) Legal		Total	$39,052
(a) Baumgarten			
	(c)	Operating	$28,959
444 West 23rd Avenue		Capital	
Spokane, WA 99203		Other	
(b) Leadership Consulting		Total	$28,959
(a) Beacon Hill Partners			
	(c)	Operating	$52,724
90 Broad Street		Capital	
New York, NY 10004		Other	$18,460
(b) Proxy Solicitation		Total	$71,184
(a) Bison Environmental			
Great Western Building	(c)	Operating	$33,253
W. 905 Riverside, Suite 316		Capital	$2,240
Spokane, WA 99201		Other	$7,800
(b) Environmental & Engineering Consulting		Total	$43,293
(a) Black & Veatch			
	(c)	Operating	$7,808
P.O. Box 27-258		Capital	$15,063
Kansas City, MO 64180		Other	$138,820
(b) Consulting Engineers		Total	$161,691

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1995	Dec. 31, 1994

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	C J Design			
	Cindy J. Rother	(c)	Operating	$58,404
	1020 Nez Perce St.		Capital	$1,600
	Moscow, ID 83843		Other	
(b)	Computer Services & Consulting		Total	$60,004
(a)	CH2M Hill			
		(c)	Operating	$15,952
	P.O. Box 91500		Capital	$103,767
	Bellevue, WA 98009-2050		Other	
(b)	Environmental & Engineering Consulting		Total	$119,719
(a)	Charles River Assoc., Inc.			
	John Hancock Tower	(c)	Operating	$9,367
	200 Clarendon Street		Capital	
	Boston, MA 02116-5092		Other	$74,490
(b)	Economic Consulting		Total	$83,857
(a)	Chemical Bank			
	Securities & Trust Services	(c)	Operating	$30,635
	Box 5747 GPO		Capital	
	New York, NY 10087-5747		Other	
(b)	Trustee fees		Total	$30,635
(a)	Citibank			
	111 Wall Street	(c)	Operating	$52,773
	Sort 4889		Capital	
	New York, NY 10043		Other	
(b)	Trustee fees		Total	$52,773
(a)	D. F. King & Co.			
		(c)	Operating	
	77 Water Street		Capital	
	New York, NY 10005-4495		Other	$154,460
(b)	Proxy Solicitation		Total	$154,460
(a)	David Evans & Associates			
		(c)	Operating	
	North 920 Washington, Suite 17		Capital	$74,987
	Spokane, WA 99201-2235		Other	
(b)	Consulting Engineers		Total	$74,987
(a)	Deloitte & Touche			
		(c)	Operating	$4,667
	111 Third Avenue		Capital	
	Seattle, WA 98101		Other	$330,180
(b)	Independent Accountants		Total	$334,847

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1995	Dec. 31, 1994

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

95	(a)	Donelan, Cleary, Wood & Maser PC			
96			(c)	Operating	$37,835
97		1275 K St. NW, Ste 850		Capital	
98		Washington, DC 20005-4006		Other	
99	(b)	Legal		Total	$37,835
100					
101	(a)	Dowell & Associates			
102			(c)	Operating	$86,103
103		P.O. Box 1400		Capital	
104		Mercer Island, WA 98040-1400		Other	
105	(b)	Tax Consultants		Total	$86,103
106					
107	(a)	Dunau Associates			
108			(c)	Operating	$99,785
109		624 E. 24th Avenue		Capital	$14,683
110		Spokane, WA 99203		Other	
111	(b)	Environmental & Engineering Consulting		Total	$114,468
112					
113	(a)	Ebasco Services, Inc.			
114			(c)	Operating	$50,663
115		210 Clay Avenue		Capital	$125,435
116		Lyndhurst, NJ 07071		Other	
17	(b)	Consulting Engineers		Total	$176,098
118					
119	(a)	Electronic Data Systems Corp-Energy Management Associates			
120			(c)	Operating	$30,010
121		P.O. Box 10552		Capital	$138,856
122		Newark, NJ 07193-0552		Other	
123	(b)	Computer Services & Consulting		Total	$168,866
124					
125	(a)	Financial Data Systems, Inc.			
126		Ed Butler	(c)	Operating	$8,176
127		2451 152nd Ave. NE		Capital	$91,626
128		Redmond, WA 98052		Other	$22,220
129	(b)	Consulting Engineers		Total	$122,022
130					
131	(a)	Hanna & Associates, Inc.			
132			(c)	Operating	$27,392
133		PO Box 2025		Capital	
134		Coeur d' Alene, ID 83814		Other	
135	(b)	Advertising Consultants		Total	$27,392
136					
137	(a)	HDR Engineering, Inc.			
138			(c)	Operating	
139		500-108th Ave. NE, Ste 1200		Capital	$25,175
140		Bellevue, WA 98004		Other	
141	(b)	Consulting Engineers		Total	$25,175
142					
143					

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a) Hill & Knowlton, Inc.			
	(c)	Operating	$2,445
420 Lexington Avenue		Capital	
New York, NY 10017		Other	$85,680
(b) Public Relations Consulting		Total	$88,125
(a) Howard Johnson & Company			
	(c)	Operating	$65,277
1111 Third Avenue, Suite 1700		Capital	
Seattle, Wa 98101		Other	
(b) Actuarial & Investment Consulting		Total	$65,277
(a) Inland Empire Employee Assistance Programs Inc.			
	(c)	Operating	$56,821
1403 Grand Blvd., Ste 206N		Capital	
Spokane, WA 99203		Other	
(b) Human Resources Consulting		Total	$56,821
(a) J. K., Inc.			
5750 Hiway 95 North	(c)	Operating	
PO Box 573		Capital	
Sandpoint, ID 83864		Other	$43,760
(b) Consulting Engineers		Total	$43,760
(a) Jerry Jackson & Associates			
	(c)	Operating	$16,536
P.O. Box 2466		Capital	
Chapel Hill, NC 27515		Other	$71,800
(b) Forecast Consulting		Total	$88,336
(a) Joe McKibben			
	(c)	Operating	
2510 Solari Drive		Capital	
Reno, NV 89509		Other	$50,000
(b) Management Consulting		Total	$50,000
(a) John Hilsen			
	(c)	Operating	
PO Box 2127		Capital	
Spokane, WA 99210-2127		Other	$25,000
(b) Environmental & Engineering Consulting		Total	$25,000
(a) Landau Assoc.			
N. 908 Howard	(c)	Operating	$173,033
Suite 206		Capital	
Spokane, WA 99201		Other	$591,510
(b) Environmental & Engineering Consulting		Total	$764,543

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	Litchfield Consulting Group			
	One Main Place, Suite 900	(c)	Operating	
	101 SW Main Street		Capital	
	Portland, OR 97204		Other	$153,370
(b)	Electric Utility Consulting		Total	$153,370
(a)	M Group Environmental Services			
		(c)	Operating	$203,612
	PO Box 3646		Capital	
	Spokane, WA 99220		Other	$26,620
(b)	Environmental & Engineering Consulting		Total	$230,232
(a)	Market Decisions Inc			
		(c)	Operating	$81,566
	8959 SW Barbur Blvd, Suite 204		Capital	
	Portland, OR 97219		Other	
(b)	Marketing Consultants		Total	$81,566
(a)	Merrill Schultz & Associates			
		(c)	Operating	$35,299
	16400 Southcenter Parkway 300		Capital	
	Seattle, WA 98188		Other	
(b)	Electric Utility Consulting		Total	$35,299
(a)	Moody's Investor Service			
		(c)	Operating	$15,919
	P.O. Box 12086		Capital	
	Newark, NJ 07101		Other	$40,010
(b)	Investment Consultants		Total	$55,929
(a)	MSC Life Ins. Co.			
		(c)	Operating	
	P.O. Box 3048		Capital	
	Spokane, WA 99220-3048		Other	$45,810
(b)	3rd Party Medical Administrator		Total	$45,810
(a)	MW Consulting Engineers			
		(c)	Operating	$4,461
	W. 222 Wall Street, Suite 200		Capital	$110,804
	Spokane, WA 99201		Other	$5,690
(b)	Consulting Engineers		Total	$120,955
(a)	Nies Mapping			
		(c)	Operating	$320
	1950 112th Avenue NE		Capital	$189,619
	Bellevue, WA 98004		Other	
(b)	Consulting Engineers		Total	$189,939

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	North by Northwest			
		(c)	Operating	$2,567
	E 520 North Foothills Dr, Suite 400		Capital	
	Spokane, WA 99201		Other	$31,940
(b)	Media Production Services		Total	$34,507
(a)	Northrop Devine & Tarbell, Inc.			
		(c)	Operating	$18,025
	500 Washington Avenue		Capital	$172,501
	Portland, ME 04103		Other	
(b)	Environmental & Engineering Consulting		Total	$190,526
(a)	O'Neill & Co.			
	1202 3rd Avenue	(c)	Operating	$30,839
	Suite 2700		Capital	
	Seattle, WA 98101		Other	$28,310
(b)	DSM Measurement & Evaluation Consulting		Total	$59,149
(a)	Object Systems International			
		(c)	Operating	
	934 N. Catalina Ave.		Capital	$348,254
	Burbank, CA 91505		Other	
(b)	Computer Consulting		Total	$348,254
(a)	Pacific Construction Consultants			
		(c)	Operating	$32,594
	4156 148th Avenue NE		Capital	
	Redmond, WA 98052		Other	
(b)	Auditing services		Total	$32,594
(a)	Pacific Hydro			
	2150 Mariner Square Drive	(c)	Operating	$35,001
	Suite 101		Capital	$6,738
	Alameda, CA 94501		Other	
(b)	FERC related consulting		Total	$41,739
(a)	Paine, Hamblen, Coffin, Brooke & Miller			
		(c)	Operating	$1,328,438
	717 W. Sprague, Suite 1200		Capital	$269,818
	Spokane, WA 99204		Other	$475,610
(b)	Legal		Total	$2,073,866
(a)	Patricia A. Newman			
		(c)	Operating	$46,783
	75 Skyline Terrace		Capital	
	Mill Valley, CA 94941		Other	$7,250
(b)	Leadership Consulting		Total	$54,033

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a) Pillsbury Madison & Sutro			
	(c)	Operating	
PO Box 60000		Capital	
San Francisco, CA 94160-2391		Other	$49,470
(b) Environmental & Engineering Consulting		Total	$49,470
(a) Power Engineering, Inc.			
	(c)	Operating	$58
P.O. Box 1066		Capital	
Hailey, ID 83333		Other	$37,120
(b) Consulting Engineers		Total	$37,178
(a) Power International			
250 NW Boulevard	(c)	Operating	
Suite 206		Capital	
Coeur d' Alene, ID 83814		Other	$57,790
(b) Consulting Engineers		Total	$57,790
(a) PSM International			
703 McKinney	(c)	Operating	
Suite 430-436		Capital	
Dallas, TX 75202-1028		Other	$30,240
(b) Environmental & Engineering Consulting		Total	$30,240
(a) Quality Resource & Services Inc			
	(c)	Operating	
P.O. Box 14781		Capital	$227,986
Spokane, WA 99214		Other	$22,770
(b) Payrolling service		Total	$250,756
(a) Raytheon Engineers & Constructors			
PO Box 8500	(c)	Operating	
S 5450		Capital	$28,357
Philadelphia, PA 19178		Other	
(b) Consulting Engineers		Total	$28,357
(a) Reginal F. Wight & Associates			
	(c)	Operating	$42,983
10431 32nd Drive SE		Capital	
Everett, WA 98208		Other	
(b) Tax Consultants		Total	$42,983
(a) Reid & Priest			
	(c)	Operating	$61,943
40 West 57th Street		Capital	
New York, NY 10019		Other	$1,437,880
(b) Legal		Total	$1,499,823

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a) Remediation Technology			
	(c)	Operating	
9 Pond Lane		Capital	
Concord, MA 01742		Other	$86,020
(b) Environmental & Engineering Consulting		Total	$86,020
(a) RLW Analytics Inc			
	(c)	Operating	
17389 Gehricke Road		Capital	
Sonoma, CA 95476		Other	$110,470
(b) DSM Measurement & Evaluation Consulting		Total	$110,470
(a) S B W Consulting Inc			
	(c)	Operating	
2820 Northup Way, Ste 230		Capital	
Bellevue, WA 98004		Other	$49,440
(b) DSM Measurement & Evaluation Consulting		Total	$49,440
(a) SSR Inc. Engineers			
	(c)	Operating	$14,751
E. 1817 Springfield, Suite G		Capital	$90,772
Spokane, WA 99202		Other	
(b) Consulting Engineers		Total	$105,523
(a) Standard & Poor Corp.			
	(c)	Operating	$1,850
25 Broadway		Capital	
New York, NY 10004		Other	$34,250
(b) Investment Consultants		Total	$36,100
(a) Sullivan & Cromwell			
	(c)	Operating	
125 Broad Street		Capital	
New York, NY 10004		Other	$39,100
(b) Legal		Total	$39,100
(a) Synergetic Resources Corporation			
	(c)	Operating	$888
111 Presidential Blvd, Suite 127		Capital	
Bala Cynwyd, PA 19004		Other	$45,110
(b) DSM Measurement & Evaluation Consulting		Total	$45,998
(a) Technical Resource Solution			
3900 W. Alameda Avenue	(c)	Operating	$19,925
Suite 1700		Capital	$220,992
Burbank, CA 91505		Other	
(b) Computer Consulting		Total	$240,917

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CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a) The OSD Alliance			
	(c)	Operating	$405,074
1365 Westgate Cntr Dr, Suite L-1		Capital	
Winston-Salem, NC 27103-2934		Other	
(b) Redesign Consulting		Total	$405,074
(a) The Wyatt Company			
	(c)	Operating	$9,472
1211 SW Fifth Avenue, Suite 2120		Capital	
Portland, OR 97204		Other	$71,670
(b) Actuarial Consultants		Total	$81,142
(a) Thomas R. Hughes & Assoc.			
	(c)	Operating	$25,422
9 Buxton Lane		Capital	
Riverside, CT 06876		Other	
(b) FERC related consulting		Total	$25,422
(a) Tucson Economic Consulting			
	(c)	Operating	$85,237
7630 North Sultan Place		Capital	
Tucson, AZ 85704		Other	
(b) Consulting Engineers		Total	$85,237
(a) Vestra Resources			
54 N. Last Chance Gulch	(c)	Operating	
Suite 13		Capital	$28,796
Helena, MT 59601		Other	
(b) Computer Consulting		Total	$28,796
(a) White Runkle Zack			
	(c)	Operating	$742,254
P.O. Box 3868		Capital	
Spokane, WA 99220		Other	$2,940
(b) Advertising Consultants		Total	$745,194
(a) WSU			
240 French	(c)	Operating	
Administration Building		Capital	$63,525
Pullman, WA 99164-1025		Other	
(b) Consulting Engineers		Total	$63,525

Sch. 13	POLITICAL ACTION COMMITTIES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
6	CONTRIBUTIONS			
8	Task Force to Renew Govenrnment		$3,500.00	100.00%
10	Montanans for Constitutional Principles		$3,500.00	100.00%
53			7,000.00	100.00%

Sch. 14	PENSION COSTS			
	Description	Last Year	This Year	% Change
1				
2	Plan Name: The Retirement Plan for The			
3	Washington Water Power Company			
4	Defined Benefit Plan______X______			
5				
6	Defined Contribution Plan___Yes_________			
7				
8	Is Plan Overfunded?______Yes____________			
9				
10	Acturial Cost Method___Yes__________________			
11				
12	IRS Code: 001			
13				
14	Annual Contribution by Employer: $0			
15				
16				
17	Accumulated Benefit Obligation	$85,358,000	$90,341,000	(5.84%)
18	Projected Benifit Obligation	$104,025,000	$107,540,000	(3.38%)
19	Fair Value of Plan Assets	$126,879,000	$119,706,000	5.65%
20				
21	Discount Rate for Benefit Obligations	7.50%	8.50%	
22	Expected Long-Term Return on Assets	9.00%	9.00%	
23				
24	Net Periodic Pension Cost:			
25	Service Cost	3,150,000	4,323,000	37.24%
26	Interest Cost	7,771,000	8,523,000	9.68%
27	Return on Plan Assets	(15,108,000)	(248,000)	(98.36%)
28	Amortization of Transition Amount	3,717,000	(11,553,000)	(410.82%)
29	Amortization of Gains or Losses			
30	Total Net Periodic Pension Cost	(470,000)	1,045,000	(322.34%)
31				
32	Minimum Required Contribution			
33	Actual Contribution			
34	Maximum Amount Deductible			
35	Benefit Payments	5,829,429	6,359,374	9.09%
36				
37	Montana Intrastate Costs:	Not Available by State		
38	Pension Costs			
39	Pension Costs Capitalized			
40	Accumulated Pension Asset (Liability) at end of year			
41				
42	Number of Company Employees:			
43	Covered by the Plan	2217	2231	0.63%
44	Not Covered by the Plan			
45	Active	1326	1319	(0.53%)
46	Retired/Survivors	642	642	0.00%
47	Deferred Vested Terminated	184	199	8.15%

Sch. 15 **OTHER POST EMPLOYMENT BENEFITS (OPEBS)** **P. 1 of 2**

	Description	Last Year	This Year	% Change
1	General Information			
2				
3	Assumptions:			
4	Discount Rate for Benefit Obligations	7.50%	8.50%	
5	Expected Long-Term Return on Assets	0	0	
6	Medical Cost Inflation Rate	8.25%	10.00%	
7	Acturial Cost Method	Projected	Projected	
8		Unit Credit	Unit Credit	
9	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
10	Method - Tax Advantaged (Yes or No)			
11	Yes VEBA			
12				
13				
14				
15				
16	Describe Changes to the Benefit Plan:			
17				
18				
19				
20	Total Company			
21				
22	Accumulated Post Retirement Benefit Obligation (APBO)	39,594,000	31,072,000	(21.52)
23	Fair Value of Plan Assets	636,000	32,000	(94.97)
24	List the amount funded through each type of funding:			
25	VEBA	636,000	32,000	(94.97)
26	401(h)			
27	Other			
28	Total amount funded			
29	*Assets reflected are estimated to cover current costs.			
30	List amount that was tax deductible for each type of funding:			
31	VEBA			
32	401(h)			
33	Other			
34	Total amount that was tax deductible			
35				
36	Net Periodic Post Retirement Benefit Cost:			
37	Service Cost	1,156,000	802,000	(30.62)
38	Interest Cost	3,006,000	2,596,000	(13.64)
39	Return on Plan Assets			
40	Amortization of Transition Obligation	1,769,000	1,606,000	(9.21)
41	Amortization of Gains and Losses			
42	Total Net Periodic Post Retirement Benefit Cost	5,931,000	5,004,000	(15.63)
43				
44	Benefit Cost Expensed			
45	Benefit Cost Capitalized			
46	Benefit Payments			
47				
48	Number of Company Employees:			
49	Covered by the Plan	2,217	2,231	0.63
50	Not Covered by the Plan			
51	Active	1,326	1,319	(0.53)
52	Retired/Spouses covered by the Plan	642	616	(4.05)
53				

Sch. 15 OTHER POST EMPLOYMENT BENEFITS (OPEBS) (cont.)

	Description	Last Year	This Year	% Change
1				
2	Montana		Not available by state	
3				
4	Accumulated Post Retirement Benefit Obligation (APBO)			
5	Fair Value of Plan Assets			
6	List the amount funded through each funding method:			
7	VEBA			
8	401(h)			
9	Other			
10	Total Amount Funded			
11				
12	List amount that was tax deductible for each type of funding:			
13	VEBA			
14	401(h)			
15	Other			
16	Total amount that was tax deductible			
17				
18	Net Periodic Post Retirement Benefit Cost:			
19	Service Cost			
20	Interest Cost			
21	Return on Plan Assets			
22	Amortization of Transition Obligation			
23	Amortization of Gains and Losses			
24	Total Net Periodic Post Retirement Benefit Cost			
25				
26	Benefit Cost Expensed			
27	Benefit Cost Capitalized			
28	Benefit Payments			
29				
30	Number of Company Employees:			
31	Covered by the Plan			
32	Not Covered by the Plan			
33	Active			
34	Retired			
35	Spouse/Dependants covered by the Plan			
36				
37	Regulatory Treatment			
38				
39	Commission authorized - most recent			
40	Docket number			
41	Order number			
42				
43	Amount recovered through rates			

Sch. 16	TOP TEN MONTANA COMPENSATED EMPLOYES (ASSIGNED OR ALLOCATED)						
	Name/Title	Base Salary*	Bonuses	Other	Total Compemsation	Total Compensation Last Year	% Increase Total Compensation
1	J. G. Hanna Station Electrician-Noxon	56,215	0	0	56,215	52,565	6.9%
2	P. A. Kelly Journeyman Operator-Noxon	53,853	0	0	53,853	48,358	11.4%
3	P. J. Aketpy Station Mechanic-Noxon	53,703	0	0	53,703	54,867	(2.1)%
4	D. W. Thomason Journeyman Operator-Noxon	49,579	0	0	49,579	49,465	0.2%
5	J. L. Garner Journeyman Operator-Noxon	48,957	0	0	48,957	44,793	9.3%
6	C. F. Webly Journeyman Operator-Noxon	48,428	0	0	48,428	49,244	(1.7)%
7	W. A. Maxvill, Jr. Journeyman Operator-Noxon	47,328	0	0	47,328	44,301	6.8%
8	T. J. Swant License Environmental Coord.	47,569	0	0	47,569	40,101	18.6%
9	L. L. Wiltse Journeyman Operator-Noxon	47,556	0	0	47,556	49,465	(3.9)%
10	T. E. Lampshire Journeyman Operator-Noxon	47,328	0	0	47,328	44,517	6.3%

*Includes overtime where applicable.

Sch. 17	COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION						
	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Paul A. Redmond Chairman of the Board, President and Chief Executive Officer	$498,742			$498,742	$484,167	2.9%
2	Jon E. Eliassen V. P. Finance and CFO	176,976		4,107	$181,083	171,819	5.1%
3	W. L. Bryan Sr. V. P. Rates and Resources	176,976			$176,976	171,819	2.9%
4	Robert D. Fukai V. P. Corporate Services and Human Resources	160,886		11,666	$172,552	177,259	(2.7%)
5	Nancy J. Racicot V.P. Operations	157,752		5,758	$163,510	130,717	20.1%

Sch. 18 **BALANCE SHEET**

	Account Title	Last Year	This Year	% Change
1	Assets and Other Debits			
2	**Utility Plant**			
3				
4	101 Electric/Gas/Common Plant in Service	1,640,479,263	1,742,677,015	6.23
5	101.1 Property Under Capital Leases			
6	102 Electric Plant Purchased or Sold		32,874,591	
7	104 Electric Plant Leased to Others			
8	105 Electric Plant Held for Future Use			
9	106 Completed Plant Not Classified - Electric			
10	107 Construction Work in Progress - Electric/Gas	55,190,943	27,315,515	(50.51)
11	108 (Less) Accumulated Depreciation	(459,676,497)	(494,088,822)	7.49
12	111 (Less) Accumulated Amortization	(6,243,790)	(2,050,490)	(67.16)
13	114 Electric/Gas Plant Acquisition Adjustment	27,299,028	26,728,593	(2.09)
14	115 (Less) Accum. Amortization of Gas Acquisition Adjustment	(3,056,967)	(4,411,819)	44.32
15	120 Nuclear Fuel			
16	TOTAL Utility Plant	1,253,991,980	1,329,044,583	5.99
17				
18	**Other Property & Investments**			
19				
20	121 Nonutility Property	3,078,212	2,975,769	(3.33)
21	122 (Less) Accum. Depr. & Amort. for Nonutility Property	(53,086)	(120,420)	126.84
22	123 Investments in Associated Companies			
23	123.1 Investments in Subsidiary Companies	93,099,743	99,743,859	7.14
24	124 Other Investments	109,275,716	102,657,332	(6.06)
25	125 Special Funds	9,203,272	12,202,384	32.59
26	TOTAL Other Property and Investments	214,603,857	217,458,924	1.33
27				
28	**Current & Accrued Assets**			
29				
30	131 Cash	(4,018,634)	(3,377,708)	(15.95)
31	132-134 Special Deposits	10,000	10,000	100.00
32	135 Working Funds	107,306	109,830	2.35
33	136 Temporary Cash Investments	0	26,948	
34	141 Notes Receivable	16,692	5,238	(68.62)
35	142 Customer Accounts Receivable	30,139,880	35,134,239	16.57
36	143 Other Accounts Receivable	2,147,485	2,327,443	8.38
37	144 (Less) Accum. Provision for Uncollectible Accounts	(1,341,448)	(1,071,059)	(20.16)
38	145 Notes Receivable - Associated Companies			
39	146 Accounts Receivable - Associated Companies	(122,621)	39,336	(132.08)
40	151 Fuel Stock	4,201,135	5,137,719	22.29
41	152 Fuel Stock Expenses Undistributed			
42	153 Residuals			
43	154 Plant Materials and Operating Supplies	10,537,110	10,758,535	2.10
44	155 Merchandise			
45	156 Other Material Supplies	80,752	64,021	
46	157 Nuclear Materials Held for Sale			
47	163 Stores Expense Undistributed	(92,435)	(41,955)	(54.61)
48	164-165 Gas Storage Accounts and Prepayments	5,764,383	20,562,553	256.72
49	171 Interest & Dividends Receivable	72,710	27,594	(62.05)
50	172 Rents Receivable	849,721	1,094,110	28.76
51	173 Accrued Utility Revenues			
52	174 Miscellaneous Current and Accrued Assets	3,192,247	3,098,122	(2.95)
53	TOTAL Current and Accrued Assets	51,544,283	73,904,966	43.38

Sch. 18 **BALANCE SHEET**

	Account Title		Last Year	This Year	% Change
1					
2	Assets & Other Debits (con't)				
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	4,868,912	5,044,968	3.62
7	182.1	Extraordinary Property Loses			
8	182.2	Unrecovered Plant & Regulatory Study Costs	4,828,707	2,113,739	(56.23)
8A	182.3	Other Regulatory Assets	181,239,980	180,413,793	(0.46)
9	183	Preliminary Survey & Investigation Charges	9,760,431	8,842,368	(9.41)
10	184	Clearing Accounts	(591,217)	923,471	(256.20)
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	51,168,092	84,873,823	65.87
13	187	Deferred Losses from Disposition of Utility Plant			
14	188	Research Development & Demonstration Expenditures	0	43,993	100.00
15	189	Unamortized Loss on Reacquired Debt	26,176,173	23,360,741	(10.76)
16	190-191	Accum. Def. Inc. Taxes & Unrecovered Purch. Gas Costs	35,657,568	32,655,148	(8.42)
17		TOTAL Deferred Debits	313,108,646	338,272,044	8.04
18					
19		TOTAL Assets & Other Debits	1,833,248,766	1,958,680,517	6.84

	Account Title		Last Year	This Year	% Change
20					
21	Liabilities and Other Credits				
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	544,608,509	570,603,199	4.77
26	202	Common Stock Subscribed			
27	204	Preferred Stock Issued	135,000,000	135,000,000	
28	205	Preferrd Stock Subscribed			
29	207	Premium on Capital Stock			
30	211	Miscellaneous Pain-In Capital			
31	213	(Less) Discount on Capital Stoak			
32	214	(Less) Capital Stock Expense	(9,897,522)	(10,030,549)	1.34
33	215	Appropriated Rertained Earnings	42,434,863	38,556,587	(9.14)
34	216	Unappropriated Retained Earnings	69,988,644	76,291,101	9.00
35	217	(Less) Reacquired Capital Stock			
36		TOTAL Proprietary Capital	782,134,494	810,420,338	3.62
37					
38	**Long Term Debt**				
39					
40	221	Bonds	322,800,000	410,800,000	27.26
41	222	(Less) Reacquired Bonds			
42	223	Advances From Associated Companies			
43	224	Other Long Term Debt	318,305,530	300,616,573	(5.56)
44	225	Unamortized Premium on Long Term Debt			
45	226	(Less) Unamort. Discount on Long Term Debt (Dr.)	(1,458,634)	(1,435,026)	(1.62)
46		TOTAL Long Term Debt	639,646,896	709,981,547	11.00

Sch. 18

BALANCE SHEET

		Account Title	Last Year	This Year	% Change
1					
2		Total Liabilities and Other Credits (con't)			
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Capital Leases - Noncurrent	0	0	
7	228.1	Accumulated Provision for Property Inurance			
8	228.2	Accumulated Provision for Injuries & Damages	1,464,034	1,598,278	9.17
9	228.3	Accumulated Provision for Pensions & Benefits	3,981,000	7,450,713	100.00
10	228.4	Accmulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12		TOTAL Other Noncurrent Liabilities	5,445,034	9,048,991	66.19
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	33,866,889	38,118,149	12.55
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies			
20	235	Customer Deposits	863,024	734,664	(14.87)
21	236	Taxes Accrued	20,144,857	17,089,360	(15.17)
22	237	Interest Accrued	10,045,865	10,954,038	9.04
23	238	Dividends Declared		227,764	100.00
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	646,581	831,300	28.57
27	242	Miscellaneous Current & Accrued Liabilities	12,737,855	16,496,751	29.51
28	243	Obligations Under Capital Leases - Current	636,536	0	(100.00)
29		TOTAL Current & Accrued Liabilities	78,941,607	84,452,026	6.98
30					
31	**Deferred Credits**				
32					
33	252	Customes Advances for Construction	2,655,506	2,344,697	(11.70)
34	253	Other Deferred Credits	11,182,175	12,032,595	7.61
35	255	Accumulated Deferred Investment Tax Credit	2,456,252	2,358,416	(3.98)
36	256	Deferred Gains from Disposition of Utility Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	310,786,802	328,041,907	5.55
39		TOTAL Deferred Credits	327,080,735	344,777,615	5.41
40					
41		TOTAL Liabilities & Other Credits	1,833,248,766	1,958,680,517	6.84

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

System of Accounts
The accounting records of The Washington Water Power Company (Company) utility operations are maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the appropriate state regulatory commissions.

Basis of Reporting
The financial statements are presented on a consolidated basis and, as such, include the assets, liabilities, revenues and expenses of the Company and its wholly owned subsidiaries, Pentzer Corporation (Pentzer), Washington Irrigation and Development Company (WIDCo), The Limestone Company and WP Finance Company. All material intercompany transactions that are not allowed recovery under regulation have been eliminated in the consolidation. As discussed in Note 14, the 1993 and 1994 operating results for ITRON are no longer consolidated and were accounted for on the equity method, and as of December 31, 1994 are now accounted for on the cost method.

The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (See Note 12).

The financial activity of each of the Company's segments is reported in the "Schedule of Information by Business Segments." Such information is an integral part of these financial statements.

Reclassifications
Certain prior year amounts related to segment information have been reclassified due to a current year change in the allocation method for common plant, plant-related costs and administrative and general expenses.

Utility Plant
The cost of additions to utility plant, including internally developed information systems, an allowance for funds used during construction and replacements of units of property and betterments, is capitalized. Maintenance and repairs of property and replacements determined to be less than units of property are charged to operating expenses. 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 (Interest Capitalized) 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 is credited currently as a noncash item to Other Income and Interest Capitalized (see Other Income below). 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 has been placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service.

The effective AFUDC rate was 10.67% in 1994, 1993 and 1992. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

Allowance for Funds Used to Conserve Energy
The Allowance for Funds Used to Conserve Energy (AFUCE) rate recovers carrying costs associated with Demand Side Management (DSM) program expenditures until such investment is included in rate base or amortized into rates. AFUCE is capitalized as a part of the cost of the DSM investment and is credited currently as a noncash item to Other Income and Interest Capitalized. The AFUCE rate in effect is the last authorized, or otherwise stipulated, rate of return from the Company's proceeding for natural gas or electric operations. The rate for Washington is adjusted for the tax effect of interest. Cash inflow related to AFUCE does not occur until the related DSM investment is placed in service.

Deferred Charges and Credits
The Company prepares its financial statements in accordance with the provisions of FAS No. 71, "Accounting for the Effects of Certain Types of Regulation." FAS No. 71 requires a cost-based, rate-regulated company to reflect the impact of regulatory decisions in its financial statements. In certain circumstances, certain costs and obligations. such as incurred costs not currently recovered through rates but expected to be recovered in the future, must be reflected in a deferred account in the balance sheet and not be reflected in income until matching revenues are recognized.

The primary regulatory assets include Investment in Exchange Power, Demand Side Management costs, the FAS 109 income tax deferral, the provision for FAS 106, and unrecovered purchased gas costs. Included in Deferred Charges, Other are debt issuance and redemption costs, which are amortized over the terms of the respective debt issues. Deferred credits include the gain on the general office building sale/leaseback being amortized over the life of the lease.

Depreciation
For utility operations, depreciation provisions are computed by a method of depreciation accounting utilizing unit rates for hydroelectric plants and composite rates for other properties. 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 6%. For utility operations, the ratio of depreciation provisions to average depreciable property was 2.56% in 1994, 2.68% in 1993 and 2.37% in 1992.

Power and Natural Gas Cost Adjustment Provisions
In 1989, the Idaho Public Utilities Commission (IPUC) approved the Company's filing for a power cost adjustment mechanism (PCA). The PCA is designed to allow the Company to change electric rates to recover or rebate a portion of the difference between actual and allowed net power supply costs. In 1994 and 1992, the Company deferred $4.1 million and $3.3 million, respectively, of net power supply costs, which resulted in like decreases in electric operating expenses. In 1993, the Company deferred $4.6 million of net power supply cost savings, which resulted in like increases in electric operating expenses. Rate changes are triggered when the deferred balance reaches $2.2 million. On January 1, 1995, a $2.2 million surcharge was implemented for the next twelve months to recover costs resulting from low streamflow conditions during 1994. A rate increase was also implemented in November 1992 to pass through accumulated costs. As of December 31, 1994, $1.4 million of costs not yet subject to a rate increase had accumulated in the PCA deferral account. On July 18, 1994, the IPUC approved an indefinite extension of the PCA.

Under established regulatory practices, the Company is also allowed to adjust its natural gas rates from time to time to reflect increases or decreases in the cost of natural gas purchased. Differences between actual natural gas costs and the natural gas costs allowed in rates are deferred and charged or credited to expense when regulators approve inclusion of the cost changes in rates.

Operating Revenues
The Company accrues estimated unbilled revenues for services provided through month-end.

Income Taxes
The Company and its eligible subsidiaries file consolidated federal income tax returns. Subsidiaries are charged or credited with the tax effects of their operations on a stand alone basis. The Company's federal income tax returns have been examined with all issues resolved, and all payments made, through the 1990 return.

Earnings Per Share
Earnings per share have been computed based on the weighted average number of common shares outstanding during the period. On November 9, 1993, the Company distributed, to shareholders of record on October 25, 1993, shares of its common stock, without par value, under a two-for-one stock split effected in the form of a 100% stock dividend. All references to number of shares and per share information have been adjusted to reflect the common stock split on a retroactive basis.

Cash
For the purposes of the Consolidated Statements of Cash Flows, the Company considers all temporary investments with an initial maturity of three months or less to be cash equivalents.

Derivative Financial Instruments
The Company's one involvement with derivative financial instruments is an interest rate cap agreement effective January 1995, for a three-year period, that sets a ceiling on the interest rate associated with a lease. Payments made under this agreement are being amortized to rent expense.

New Accounting Standards
Effective January 1, 1994, the Company adopted FAS No. 115, entitled "Accounting for Certain Investments in Debt and Equity Securities." Under FAS No. 115, investments in debt and marketable equity securities are classified as "available for sale" and are recorded at fair value. Investments totalling $34.1 million and $27.9 million are included on the Consolidated Balance Sheets as other property and investments and current assets, respectively. Unrealized investment gains, net of taxes, added $14.3 million to the Consolidated Statements of Capitalization as of December 31, 1994 as a separate component of shareholders' equity.

NOTE 2. RETIREMENT PLANS AND OTHER POSTRETIREMENT BENEFITS

Effective January 1, 1993, the Company adopted FAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." FAS No. 106 requires the Company to accrue the estimated cost of postretirement benefit payments during the years the employee provides services. The Company previously expensed the cost of these benefits, which are principally health care, as claims were incurred. FAS No. 106 allows recognition of the unrecognized transition obligation in the year of adoption or the amortization of such obligation over a period of up to twenty years. The Company elected to amortize this obligation of approximately $34,500,000 over a period of twenty years.

The Company has received accounting orders from the Washington Utilities and Transportation Commission (WUTC) and the IPUC allowing the current deferral of expense accruals under this Statement as a regulatory asset for future recovery. At such time that rate recovery is requested and allowed, cumulative deferrals will be amortized over the remainder of the twenty-year amortization period. The Company expects to be able to recover the amortized amounts. Therefore, the Company's cash flows and income from operations are not affected by implementation of this Statement.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. In 1994, 1993 and 1992, the Company recognized $1,270,000, $1,250,000 and $1,290,000, respectively, as an expense for postretirement health care and life insurance benefits. The following table sets forth the health care plan's funded status at December 31, 1994 and 1993.

Accumulated postretirement benefit obligation (thousands of dollars):

	1994	1993
Retirees	506	509
Fully eligible plan participants	1,340	1,341
Other active plan participants	110	111
Total participants	1,956	1,961
Fair value of plan assets	$32	$636
Accumulated postretirement benefit obligations in excess of plan assets	$34,468	$38,964
Unrecognized transition obligation	$33,548	$38,413
Accrued postretirement benefit cost	$2,966	$3,981

Net postretirement benefit cost for 1994 and 1993 consisted of the following components (thousands of dollars):

	1994	1993
Service cost - benefits earned during the period	$475	$776
Return on the plan assets (if any)	-	-
Interest cost on accumulated postretirement benefit obligation	$1,539	$2,018
Amortization of transition obligation	$952	$1,187

The currently assumed health care cost trend rate used in measuring the accumulated postretirement benefit obligation is 12% for 1994, decreasing linearly each successive year until it reaches 7% in 1998. 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, 1994 and net postretirement health care cost by approximately $1,552,000. The assumed discount rate used in determining the accumulated postretirement benefit obligation was 8.5%.

The Company has a pension plan covering substantially all of its regular full-time employees. Some of the Company's subsidiaries also participate in this plan. Individual benefits under this plan are based upon years of service and the employee's average compensation as specified in the Plan. The Company's funding policy is to contribute annually an amount equal to the net periodic pension cost, provided that such contributions are not less than the minimum amounts required to be funded under the Employee Retirement Income Security Act, nor more than the maximum amounts which are currently deductible for tax purposes. Pension fund assets are invested primarily in marketable debt and equity securities. The Company also has another plan which covers the executive officers.

Net pension credit for 1994, 1993 and 1992 is summarized as follows:	1994	1993	1992
	(Thousands of Dollars)		
Service cost-benefits earned during the period	$ 4,323	$ 3,150	$ 2,846
Interest cost on projected benefit obligation	8,523	7,771	7,390
Actual return on plan assets	(248)	(15,108)	(12,257)
Net amortization and deferral	(11,553)	3,717	886
Net periodic pension cost (income)	1,045	(470)	(1,135)
Less amounts charged (credited) to construction and other accounts	-	-	(24)
Net pension cost credited to operating expenses	$ 1,045	$ (470)	$ (1,111)

The funded status of the Plan and the pension liability at December 31, 1994, 1993 and 1992, are as follows:

	1994	1993	1992
	(Thousands of dollars)		
Actuarial present value of benefit obligations:			
Accumulated benefit obligations (including vested benefits of $(88,596,000), $(84,531,000) and $(76,226,000), respectively)	$ (90,341)	$ (85,368)	$ (76,853)
Projected benefit obligation for service rendered to date	$(107,540)	$(104,025)	$ (95,446)
Plan assets at fair value	119,706	126,879	118,883
Plan assets in excess of projected benefit obligation	12,166	22,854	23,437
Unrecognized net gain from returns different than assumed	(17,939)	(21,503)	(19,733)
Prior service cost not yet recognized in pension cost	14,803	7,983	8,568
Unrecognized net asset at year-end (being amortized over 11 to 19 years)	(11,359)	(12,445)	(13,531)
Regulatory deferrals (1)	(1,841)	(3,256)	(1,381)
Pension liability	$ (4,170)	$ (6,367)	$ (2,640)
Assumptions used in calculations were:			
Discount rate at year-end	8.5%	7.5%	8.5%
Rate of increase in future compensation level	4.0%	4.0%	5.0%
Expected long-term rate of return on assets	9.0%	9.0%	9.0%

(1) The Company has received accounting orders from regulatory authorities requiring the Company to defer the difference between pension cost as determined under FAS 87 and that determined for ratemaking purposes.

NOTE 3. ACCOUNTING FOR INCOME TAXES

The Company adopted Statement of Financial Accounting Standards (FAS) No. 109, "Accounting for Income Taxes," effective January 1, 1993, which supersedes Accounting Principles Board Opinion 11 previously adopted by the Company. FAS No. 109 establishes revised financial accounting and reporting standards for the effects of income taxes.

As of December 31, 1994 and 1993, respectively, the Company had recorded net regulatory assets of $174,349,000 and $177,786,000 related to the probable recovery of FAS No. 109 deferred tax liabilities from customers through future rates. Such net regulatory assets will be adjusted by amounts recovered through rates.

Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes, and (b) tax credit carryforwards. The net deferred federal income tax liability consists of the following (thousands of dollars):

	1994	1993
Deferred tax liabilities:		
Differences between book and tax bases of utility plant	$317,991	$297,175
Loss on reacquired debt	8,216	9,243
Deferred natural gas credits	1,095	2,679
Other	8,957	5,575
Total deferred tax liabilities	336,259	314,672
Deferred tax assets:		
Reserves not currently deductible	14,429	14,486
Contributions in aid of construction	3,710	2,975
Gain on sale of office building	1,555	1,647
Other	6,398	6,659
Total deferred tax assets	26,092	25,767
Net deferred tax liability	$310,167	$288,905

Refer to page 261 of the Federal Energy Regulatory Commission Form 1 for a reconciliation of federal income taxes.

NOTE 4. LONG-TERM DEBT

The annual sinking fund requirements and maturities for the next five years for First Mortgage Bonds and Medium-Term Notes outstanding at December 31, 1994 are as follows:

Year Ended December 31	Maturities	Sinking Fund Requirements (Thousands of Dollars)	Total
1995	$45,000	$3,967	$48,967
1996	35,000	3,767	38,767
1997	31,000	3,657	34,657
1998	10,000	3,657	13,657
1999	47,500	3,447	50,947

The sinking fund requirements may be met by certification of property additions at the rate of 167% of requirements. All of the utility plant is subject to the lien of the Mortgage and Deed of Trust securing outstanding First Mortgage Bonds.

In 1993 and 1992, $25,000,000 and $113,000,000, respectively, of unsecured Medium-Term Notes, Series A and B were issued. At December 31, 1994, the Company had outstanding $242,500,000 of such notes with maturities between 1 and 29 years and with interest rates varying between 5.50% and 9.58%.

In 1994 and 1993, $88,000,000 and $225,000,000, respectively, of Secured Medium-Term Notes, Series A and B were issued. At December 31, 1994, the Company had outstanding $313,000,000 of such notes with maturities between 2 and 29 years and with interest rates varying between 4.72% and 8.25%. As of December 31, 1994, the Company had remaining authorization to issue up to $187,000,000 of such notes of the $250,000,000 originally authorized.

At December 31, 1994, the Company had $58,000,000 outstanding under borrowing arrangements which will be refinanced in 1995. See Note 5 for details of credit agreements.

In accordance with FAS No. 107 "Disclosures About Fair Value of Financial Instruments," the fair value of the Company's long-term debt at December 31, 1994 and 1993 is estimated to be $673.0 million, or 93% of the carrying value and $690.0 million, or 107% of the carrying value, respectively. These estimates are based on available market information and appropriate valuation methodologies.

NOTE 5. BANK BORROWINGS AND COMMERCIAL PAPER

At December 31, 1994, the Company maintained total lines of credit with various banks under two separate credit agreements amounting to $160,000,000. The Company has a revolving line of credit expiring December 9, 1997, which provides a total credit commitment of $70,000,000. The second revolving credit agreement is composed of two tranches totaling $90,000,000. The one-year tranche is renewable each year through 1995 and provides for up to $50,000,000 of notes to be outstanding at any one time. The three-year tranche expires September 30, 1995, and provides for up to $40,000,000 of notes to be outstanding at any one time. The Company pays commitment fees of up to 0.1875% per annum on the average daily unused portion of each credit agreement.

In addition, under various agreements with banks, the Company can have up to $60,000,000 in loans outstanding at any one time, with the loans available at the banks' discretion. These arrangements provide, if funds are made available, for fixed-term loans for up to 180 days at a fixed rate of interest. In December 1994, the Company terminated its commercial paper program.

Balances and interest rates of bank borrowings under these arrangements were as follows:

	Years Ended December 31,	
	1994	1993
	(Dollars in thousands)	
Balance outstanding at end of period:		
Fixed-term loans	$ 33,000	$ 44,001
Commercial paper	-	20,000
Revolving credit agreement	25,000	4,000
Maximum balance during period:		
Fixed-term loans	$ 52,000	$ 69,000
Commercial paper	20,000	20,000
Revolving credit agreement	32,000	28,000
Average daily balance during period:		
Fixed-term loans	$ 29,373	$ 24,499
Commercial paper	-	7,791
Revolving credit agreement	10,941	5,030

Average annual interest rate during period:		
Fixed-term loans	4.64%	3.38%
Commercial paper	-	3.46
Revolving credit agreement	4.49	3.49
Average annual interest rate at end of period:		
Fixed-term loans	6.28%	3.55%
Commercial paper	-	3.58
Revolving credit agreement	6.28	3.65

NOTE 6. ACCOUNTS RECEIVABLE SALE

The Company has entered into an agreement whereby it can sell, on a revolving basis, up to $40,000,000 of interests in certain accounts receivable, both billed and unbilled. The Company is obligated to pay fees which 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 operating expenses. At both December 31, 1994 and 1993, $40,000,000 in receivables had been sold pursuant to the agreement.

NOTE 7. PREFERRED STOCK

Cumulative Preferred Stock Not Subject to Mandatory Redemption:
The dividend rate on Flexible Auction Preferred Stock, Series J is reset every 49 days based on an auction. During 1994, the dividend rate varied from 3.000% to 4.950% and at December 31, 1994, was 4.950%. Series J is subject to redemption at the Company's option at a redemption price of 100% per share plus accrued dividends.

Cumulative Preferred Stock Subject to Mandatory Redemption:

Redemption requirements:

$8.625, Series I - On June 15, 1996, 1997, 1998, 1999 and 2000, the Company must redeem 100,000 shares at $100 per share plus accumulated dividends. The Company may, at its option, redeem up to 100,000 shares in addition to the required redemption on any redemption date.

$6.95, Series K - On September 15, 2002, 2003, 2004, 2005 and 2006, the Company must redeem 17,500 shares at $100 per share plus accumulated dividends through a mandatory sinking fund. Remaining shares must be redeemed on September 15, 2007. The Company has the right to redeem an additional 17,500 shares on each September 15 redemption date.

There are $40 million in mandatory redemption requirements during the 1995-1999 period.

In accordance with FAS No. 107 "Disclosures About Fair Value of Financial Instruments," the fair value of the Company's preferred stock at December 31, 1994 and 1993 is estimated to be $135.1 million, or 100% of the carrying value and $93.8 million, or 110% of the carrying value, respectively. These estimates are based on available market information and appropriate valuation methodologies.

NOTE 8. COMMON STOCK

On November 9, 1993, the Company distributed, to shareholders of record on October 25, 1993, shares of its common stock, without par value, under a two-for-one stock split effected in the form of a 100% stock dividend. All references to number of shares and per share information have been adjusted to reflect the common stock split on a retroactive basis.

In April 1990, the Company sold 1,000,000 shares of its common stock to the Trustee of the Investment and Employee Stock Ownership Plan for Employees of the Company (Plan) for the benefit of the participants and beneficiaries of the Plan. In payment for the shares of Common Stock, the Trustee issued a promissory note payable to the Company in the amount of $14,125,000. Dividends paid on the stock held by the Trustee, plus Company contributions to the Plan, if any, are used by the Trustee to make interest and principal payments on the promissory note. The balance of the promissory note receivable from the Trustee ($12,266,750 at December 31, 1994) is reflected as a reduction to common equity. The shares of Common Stock are allocated to the accounts of participants in the Plan as the note is repaid. During 1994, the cost recorded for the Plan was $2,724,000. This included the cost for an additional 272,278 shares which were issued for ongoing employee and Company contributions to the Plan. Interest on the note payable, cash and stock contributions to the Plan and dividends on the shares held by the Trustee were $1,195,000, $2,264,000 and $1,224,000, respectively.

In February 1990, the Company adopted a shareholder rights plan, which was subsequently amended, pursuant to which holders of Common Stock outstanding on March 2, 1990, or issued thereafter, have been 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 two-hundredth of a share of Preferred Stock of the Company, without par value, at an exercise price of $40, subject to certain adjustments, regulatory approval and other specified conditions. The Rights will be exercisable only if a person or group acquires 10% or more of the Common Stock or announces a tender offer, the consummation of which would result in the beneficial ownership by a person or group of 10% or more of the Common Stock. The Rights may be redeemed, at a redemption price of $0.005 per Right, by the Board of Directors of the Company at any time until any person or group has acquired 10% or more of the Common Stock. The Rights will expire on the earlier of February 16, 2000 and the effective time of the merger with SPR, SPPC and Resources West.

In November 1991, the Company received authorization to issue from time to time 1,500,000 shares of Common Stock under a Periodic Offering Program (POP). During 1992, the remaining 1,107,600 shares of the first POP were issued under this program for net proceeds of $18.0 million. In the second half of 1992, the Company received authorization to issue a second 1,500,000 shares of common stock under the POP. Through December 31, 1994, 927,600 shares of the second POP were issued for net proceeds of $17.3 million.

The Company has a Dividend Reinvestment and Stock Purchase Plan under which the Company's stockholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's Common Stock.

Sales of Common Stock for 1994 and 1993 are summarized below (in thousands of dollars):

	1994		1993	
	Shares	Amount	Shares	Amount
Balance at January 1	52,757,545	$544,609	50,888,130	$508,202
Employee Investment Plan (401-K)	272,278	4,302	165,335	3,216
Dividend Reinvestment Plan	1,390,873	21,692	1,127,680	21,779
Periodic Offering	-	-	576,400	11,412
Total Issues	1,663,151	25,994	1,869,415	36,407
Balance at December 31	54,420,696	$570,603	52,757,545	$544,609

NOTE 9. LEASES

The Company has entered into several lease arrangements involving various assets, with minimum terms ranging from eleven months to seventeen years and expiration dates from 1995 to 2011. The lease provisions obligate the Company to sell on behalf of the lessor or purchase the associated asset at a specified percentage of the asset's fair value if the lease is not renewed. Rent expense for the years ended December 31, 1994, 1993 and 1992 was $2.3 million, $1.9 million and $1.8 million, respectively. Future minimum lease payments (thousands of dollars) required under operating leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 1994 are estimated as follows:

Year ending December 31:	
1995	$ 8,424
1996	7,283
1997	6,872
1998	1,847
1999	2,257
Later years	27,086
Total minimum payments required	$ 53,769

The Company also has various other operating leases, which are charged to operating expense, consisting of a large number of small, relatively short-term, renewable agreements for various items, such as office equipment and office space.

NOTE 10. DISCONTINUED COAL MINING OPERATIONS

Washington Irrigation & Development Company (WIDCo) owned an undivided one-half interest in coal mining properties near Centralia, Washington, which it operated and which supplied coal to the Centralia Steam Electric Generating Plant owned 15% by the Company. On July 31, 1990, WIDCo sold its 50% interest in the Centralia coal mining properties for $40.8 million. Net income of $2.4 million in 1992 resulted from accounting adjustments and a refund of federal income taxes for years prior to the sale. The consolidated financial statements have been reclassified to reflect the continuing operations of the Company. The revenues, expenses, assets and liabilities of the discontinued operations have been reclassified from those categories and netted into single line items for discontinued operations in the Balance Sheets and Income Statements.

NOTE 11. COMMITMENTS AND CONTINGENCIES

Supply System Project 3

In 1985, the Company and the Bonneville Power Administration (BPA) reached a settlement surrounding litigation related to the suspension of construction of Washington Public Power Supply System (Supply System) Project 3. Project 3 is a partially constructed 1,240 MW nuclear generating plant in which the Company has a 5% interest. Under the settlement agreement, the Company receives power deliveries from BPA from 1987 to 2017 in proportion to the Company's investment in Project 3.

The only material claim against the Company arising out of the Company's involvement in Project 3, which has been pending since October 1982 in the United States District Court for the Western District of Washington (District Court), is the claim of Chemical Bank, as bond fund trustee for Supply System Projects 4 and 5, against all owners of Projects 1, 2 and 3 for unjust enrichment in the allocation of certain costs of common services and facilities among the Supply System's five nuclear projects. Projects 4 and 5 were being constructed adjacent to Projects 1 and 3, respectively, under a plan to share certain costs. Chemical Bank was seeking a reallocation of $495 million in costs (plus interest since commencement of construction in 1976) originally allocated to Projects 4 and 5.

On January 24, 1995, the Company executed a Memorandum of Understanding (MOU) which is intended to settle all remaining claims in the "cost sharing" litigation. The other parties to the MOU are expected to include Chemical Bank, as trustee for the holder of Supply System Projects 4 and 5 bonds; the Supply System; BPA; certain public utility participants in those projects; and Puget Sound Power & Light Company (Puget), and Portland General Electric Company (PGE), Puget and PGE being two of the other three investor-owned utilities which held minority ownership interests in Project 3.

The MOU provides for the Company to pay $500,000 in settlement of all claims, and as part of a total $55,000,000 payment to Chemical Bank. In the MOU, the Company also agrees to give up any claims relating to the Company's bridge loans made to the Supply System in 1981. In exchange, the Company would be released from all pending cost-sharing litigation claims. The MOU contemplates and provides agreement on consolidation of the Project 5 and Project 3 sites for site restoration purposes, if BPA and the Supply System decide to thus consolidate the site. In the event that occurs, the Company would be completely indemnified from any additional costs by a separate agreement with BPA. Under the MOU, the Company's payment to Chemical Bank is due in July, 1995, and it is expected that a final settlement agreement and dismissal of the litigation will occur before or contemporaneously with that payment.

Nez Perce Tribe

On December 6, 1991, the Nez Perce Tribe filed an action against the Company in U. S. District Court for the District of Idaho alleging, among other things, that two dams formerly operated by the Company, the Lewiston Dam on the Clearwater River and the Grangeville Dam on the South Fork of the Clearwater River, provided inadequate passage to migrating anadromous fish in violation of rights under treaties between the Tribe and the United States made in 1855 and 1863. The Lewiston and Grangeville Dams, which had been owned and operated by other utilities under hydroelectric licenses from the Federal Power Commission (the "FPC", predecessor of the FERC) prior to acquisition by the Company, were acquired by the Company in 1937 with the approval of the FPC, but were dismantled and removed in 1973 and 1963, respectively. The Tribe initially indicated through expert opinion disclosures that they were seeking actual and punitive damages of $208 million. However, supplemental disclosures reflect allegations of actual loss under different assumptions of between $425 million and $650 million.

Discovery had been stayed pending a decision by the Court on a case involving some similar issues brought by the Tribe against Idaho Power Company. The Court has since decided these issues and has dismissed all claims against Idaho Power. The Idaho Power case has now been appealed by the Nez Perce Tribe to the Ninth Circuit Court of Appeals. On November 21, 1994, the Company filed its Motion and Brief in Support of Summary Judgment of Dismissal. The Nez Perce Tribe has filed a reply brief, and has requested oral argument. No hearing on the Company's Motion for Summary Judgment has been scheduled by the Court and the matter is not set for trial. The Company is presently unable to assess the likelihood of an adverse outcome in this litigation, or estimate an amount or range of potential loss in the event of an adverse outcome.

Little Falls Project

Pending before the U. S. District Court in the Eastern District of Washington is the case of Spokane Tribe of Indians v. WWP, which was filed in 1982. This matter involves a claim of the Spokane Tribe of Indians for damages arising out of the Company's Little Falls Hydroelectric Development that was constructed on the Spokane River pursuant to a 1905 Act of Congress. The Tribe claimed the Company's dam interfered with Indian fishing rights and sought a declaratory judgment and quiet title to part of the property comprising the Little Falls Hydroelectric Development. However, the Company, the Tribe and the Bureau of Indian Affairs signed a settlement agreement on September 9, 1994. The Secretary of the Interior and the Tribe have executed an irrevocable easement and license to WWP to the property comprising the Little Falls Hydroelectric Development. The lawsuit has been dismissed with prejudice. The settlement agreement provides for an initial payment of $1.0 million to the Tribe plus an additional $3.2 million to be paid over the next five years for fish and wildlife enhancement projects. An accrual of $4.2 million was made during June 1994 and is reflected in the Company's financial statements. Annual payments will also be made to the Tribe, which will be tied to generation at the Little Falls Project and escalate at the rate of 4.1 percent per year, with the first installment of $375,000 expected to be made by mid-April 1995.

Oil Spill

The Company recently completed an updated investigation of an oil spill that occurred several years ago in downtown Spokane at the site of the Company's steam heat plant. The Company purchased the plant in 1916 and operated it as a non-regulated plant until it was deactivated in 1986 in a business decision unrelated to the spill. After the Bunker C fuel oil spill, initial studies suggested that the oil was being adequately contained by both geological features and man-made structures. The Washington State Department of Ecology (DOE) concurred with these findings. However, more recent tests confirm that the oil has migrated approximately one city block beyond the steam plant property. On December 6, 1993, the Company asked the DOE to enter into negotiations for a Consent Decree which will provide for additional remedial investigation and a feasibility study. The Consent Decree, entered on November 8, 1994, provided for 22 additional soil borings to be made around the site, which have been completed. In December 1993, the Company established a reserve of $2.0 million, and in December 1994 increased it to $3.1 million based on more current estimates.

Firestorm

On October 16, 1991, gale-force winds struck a five-county area in eastern Washington and a seven-county area in northern Idaho. These winds were responsible for causing 92 separate wildland fires, resulting in two deaths and the loss of 114 homes and other structures, some of which were located in the Company's service territory. Four separate class action lawsuits were filed against the Company by private individuals in the Superior Court of Spokane County on October 13, 1993. These suits concern fires identified as Midway, Golden Cirrus, Nine Mile and Chattaroy. All of these suits were certified as class actions on September 16, 1994, and bifurcated for trial of liability and damage issues by order of the same date. The Company's Motion for Reconsideration was denied on October 21, 1994, and a Motion for Discretionary Review of the Court's decision on certification of class actions was timely filed with the Washington Court of Appeals (Division III) on November 14, 1994.

The Company was also served with two suits in Spokane County Superior Court filed on April 20, 1994 and on September 15, 1994, both of which sought individual damages from separate fires within the Chattaroy Fire complex. Five additional and separate suits were brought by Grange Insurance Company, and were filed in Spokane County Superior Court on October 10, 1994, for approximately $2.2 million paid to Grange insureds for the same fire areas. Two additional class action suits were also filed - one in Lincoln County Superior Court, filed on October 14, 1994, for a fire known as "Nine Mile West" (previously included in the Spokane County Nine Mile suit certified as a class action), and the second in Spokane County Superior Court, filed on October 14, 1994, for the Ponderosa Fire area (which had not been the subject of previous suit). Neither of these suits has yet been certified as a class action, although the Lincoln County suit has been transferred to Spokane County pursuant to decision of the Lincoln County Superior Court on February 21, 1995.

Complainants in all cases allege various theories of tortious conduct, including negligence, creation of a public nuisance, strict liability and trespass; in most cases, complainants allege that fires were caused by electric distribution lines downed by the wind. The lawsuits seek recovery for property damage, emotional and mental distress, lost income and punitive damages, but do not specify the amount of damages being sought. Since little discovery has been conducted and the classes are not yet formed, the Company is presently unable to assess the likelihood of an adverse outcome or estimate an amount or range of potential loss in the event of an adverse outcome. The Company was previously presented with a claim from the Washington State Department of Natural Resources (DNR) for fire suppression costs associated with five of these fires in eastern Washington. The total of the DNR claim was $1.0 million. On July 22, 1993, the Company entered into a settlement with the DNR whereby the Company agreed to pay $200,000 to DNR in full settlement of any and all DNR claims; however, there was no admission of liability on the part of the Company.

Williams Lake Lawsuit

On February 2, 1995, a lawsuit was commenced in Spokane County Superior Court against the Company and its subsidiary, Pentzer, by Tondu Energy Systems, Inc. and T.E.S. Williams Lake Partnership alleging contract violations, conspiracy, misrepresentation and breach of fiduciary duties in regard to the 1993 sale of Pentzer Energy Services, Inc. to B.C. Gas, Inc. The suit claims damages in excess of $10 million, plus exemplary damages, prejudgment interest, costs and attorneys' fees. Also named as defendants are B.C. Gas, Inc., Inland Pacific Energy (Williams Lake) Corp. and the former Pentzer Energy Services, Inc., subsidiaries involved in the sale, WP Energy Company, WP Energy Canada, Ltd. and WP Energy Canada (Williams Lake) Ltd. The claims involve an alleged first right to purchase interests in the Williams Lake, British Columbia wood-fired generating station. Discovery with regard to the lawsuit has not yet commenced. The Company and Pentzer intend to vigorously defend against all of the claims.

Other Contingencies

The Company has long-term contracts related to the purchase of fuel for thermal generation, natural gas and hydroelectric power. Terms of the natural gas purchase contracts range from one month to five years and the majority provide for minimum purchases at the then effective market rate. The Company also has various agreements for the purchase, sale or exchange of power with other utilities, cogenerators, small power producers and government agencies. For information relating to certain long-term purchased power contracts, see Note 13.

NOTE 12. JOINTLY-OWNED ELECTRIC FACILITIES

The Company is involved in several jointly owned generating plants. Financing for the Company's ownership in the projects is provided by the Company. The Company's share of related operating and maintenance expenses for plants in service is included in corresponding accounts in the Consolidated Statements of Income. The following table indicates the Company's percentage ownership and the extent of the Company's investment in such plants at December 31, 1994:

Project	KW of Installed Capacity	Fuel Source	Ownership (%)	Company's Current Share of Plant in Service	Accumulated Depreciation	Net Plant In Service	Construction Work in Progress
				(Thousands of Dollars)			
Centralia	1,330,000	Coal	15%	$ 55,112	$31,173	$ 23,939	$930
Colstrip 3 & 4	1,556,000	Coal	15	269,460	80,181	189,279	-

NOTE 13. LONG-TERM PURCHASED POWER CONTRACTS WITH REQUIRED MINIMUM PAYMENTS

Under fixed contracts with Public Utility Districts, the Company has agreed to purchase portions of the output of certain generating facilities. Although the Company has no investment in such facilities, these contracts provide that the Company pay certain minimum amounts (which are based at least in part on the debt service requirements of the supplier) whether or not the facility is operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in operations and maintenance expense in the Consolidated Statements of Income. Information as of December 31, 1994, pertaining to these contracts is summarized in the following table:

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs(2)	Debt Service Costs(3)	Revenue Bonds Outstanding	Contract Expiration Date
Public Utility District (PUD) Contracts:			(Thousands of Dollars)			
Chelan County PUD:						
Lake Chelan Project...........	100.0% (1)	58,000	$3,089	$ 310	$ 7,628	1995
Rocky Reach Project..........	2.9	37,000	1,093	584	4,354	2011
Grant County PUD:						
Priest Rapids Project..........	6.1	55,000	1,470	1,043	8,001	2005
Wanapum Project...............	8.2	75,000	2,088	1,575	15,287	2009
Douglas County PUD:						
Wells Project....................	3.9	30,000	977	609	7,617	2018
Totals		255,000	$8,717	$4,121	$42,887	

(1) The Company purchases 100% of the Lake Chelan Project output and sells back to the PUD about 40% of the output to supply local service area requirements.
(2) The annual costs will change in proportion to the percentage of output allocated to the Company in a particular year. Amounts represent the operating costs for the year 1994.
(3) Included in annual costs.

Actual expenses for payments made under the above contracts for the years 1994, 1993 and 1992, were $8,717,000 $8,721,000 and $8,433,000, respectively. The estimated aggregate amounts of required minimum payments (the Company's share of debt service costs) under the above contracts for the next five years are $3,829,000 in 1995, $3,750,000 in 1996, $3,616,000 in 1997, $5,355,000 in 1998 and $5,392,000 in 1999 (minimum payments thereafter are dependent on then market conditions). In addition, the Company will be required to pay its proportionate share of the variable operating expenses of these projects.

NOTE 14. ACQUISITIONS AND DISPOSITIONS

During 1994, Pentzer acquired two companies, one involved in bindery services for the advertising, printing, publishing and direct mail industries and the other in the design and manufacture of panel saws, panel routers and accessories. During 1993, Pentzer acquired three companies, two involved in financial services and one in point-of-purchase display manufacturing. Sales of companies involved in telecommunications, technology and energy services resulted in transactional gains of $7.1 million in 1993. At December 31, 1994, Pentzer had approximately $167 million in assets compared to $130 million at the end of 1993.

In 1992, Pentzer's common stock ownership in ITRON was reduced from approximately 60% to approximately 40% as a result of the issuance of common stock by ITRON in an acquisition. Accordingly, beginning in 1992, Pentzer's share of ITRON's earnings was accounted for by the equity method and was included in Other Income-Net and its investment in ITRON was reflected on the balance sheet under Other Property and Investments. ITRON's initial public offering in November 1993 and Pentzer's sales of ITRON stock during 1993 and 1994 resulted in a reduction in Pentzer's ownership interest to approximately 14%. As a result, Pentzer's investment in ITRON, beginning in December 1994, is accounted for by the cost method.

On December 30, 1994, the IPUC approved the transfer of ownership of all PacifiCorp's electric properties in northern Idaho to the Company. The cash purchase price was approximately $33 million. The Company commenced operations of the properties on January 1, 1995. The purchase adds approximately 9,800 customers. The Company reduced most customers' rates to 1% below PacifiCorp's current rates and instituted a four-year rate freeze. At the end of the rate freeze, rates will be adjusted to the levels then in effect in the Company's other service areas in northern Idaho. The Company believes this acquisition will not have a material impact on its operating revenues or its results of operations.

NOTE 15. PROPOSED MERGER

In June 1994, the Company, Sierra Pacific Resources (SPR), Sierra Pacific Power Company, a subsidiary of SPR (SPPC), and Resources West Energy Corporation, a newly formed subsidiary of the Company (Resources West) entered into an Agreement and Plan of Reorganization and Merger, dated as of June 27, 1994, as amended October 4, 1994 which provides for the merger of the Company, SPR and SPPC with and into Resources West. The merger is designed to qualify as a pooling-of-interests for accounting and financial reporting purposes. Under this method of accounting, the recorded assets and liabilities of WWP, SPR and SPPC will be carried forward to the consolidated financial statements of Resources West at their recorded amounts; income of Resources West will include income of WWP, SPR and SPPC for the entire fiscal year in which the merger occurs; and the reported income of the separate corporations for prior periods will be combined and restated as income of Resources West.

The cost savings from the merger are estimated to approximate $450 million, net of merger transaction and transition costs, over a 10 year period following the consummation of the merger.

The following pro forma condensed financial information combines the historical consolidated balance sheets and statements of income of WWP and SPR after giving effect to the merger. The unaudited pro forma condensed consolidated balance sheet at December 31, 1994 gives effect to the merger as if it had occurred at December 31, 1994. The unaudited pro forma condensed consolidated statements of income for each of the three years in the period ended December 31, 1994 give effect to the merger as if it had occurred at January 1, 1992. These statements are prepared on the basis of accounting for the merger as a pooling-of-interests and are based on the assumptions set forth in the paragraph below. The pro forma condensed financial information has been prepared from, and should be read in conjunction with the Company's historical consolidated audited financial statements and related notes thereto of which this note is a part and SPR's historical consolidated audited financial statements and related notes thereto included in reports filed by SPR pursuant to the Securities Exchange Act, as amended. The information contained herein with respect to SPR and its subsidiaries has been supplied by SPR. The information is not necessarily indicative of the financial position or operating results that would have occurred had the merger been consummated on the date, or at the beginning of the periods, for which the merger is being given effect, nor is it necessarily indicative of future operating results or financial position.

Intercompany transactions (including purchased and exchanged power transactions) between WWP and SPR during the periods presented were not material and, accordingly, no pro forma adjustments were made to eliminate such transactions. For comparative purposes, certain historical amounts have been reclassified to conform to the pro forma condensed financial statement format. The $450 million net cost savings estimated to be achieved by the merger are not reflected in the pro forma financial statements. All references to per share information for WWP have been adjusted to reflect the two-for-one common stock split which became effective on November 9, 1993. Pro forma per share data and common shares outstanding for Resources West give effect to the conversion of each share of WWP Common Stock into one share of Resources West Common Stock and the conversion of each share of SPR Common Stock into 1.44 shares of Resources West Common Stock.

Pro Forma Condensed Consolidated Balance Sheet (in thousands of dollars):

At December 31, 1994	WWP	SPR	PRO FORMA (unaudited)
Assets			
Utility plant in service-net	$1,802,280	$1,760,941	$3,563,221
Construction work in progress	27,316	74,893	102,209
Total	1,829,596	1,835,834	3,665,430
Accumulated depreciation and amortization	500,551	504,356	1,004,907
Net utility plant	1,329,045	1,331,478	2,660,523
Other property and investments	202,760	17,006	219,766
Current assets	136,566	126,296	262,862
Deferred charges	325,882	157,923	483,805
Total assets	$1,994,253	$1,632,703	$3,626,956
Capitalization and Liabilities			
Common stock and additional paid-in capital	$ 570,603	$ 450,660	$1,021,263
Other shareholders equity	106,891	58,062	164,953
Preferred stock	135,000	93,515	228,515
Long-term debt	721,146	561,909	1,283,055
Total capitalization	1,533,640	1,164,146	2,697,786
Current liabilities	132,517	145,528	278,045
Deferred income taxes	310,167	156,958	467,125
Other deferred credits	16,757	166,071	182,828
Minority interest	1,172	-	1,172
Total capitalization and liabilities	$1,994,253	$1,632,703	$3,626,956
Common shares outstanding (thousands)	54,421	29,405	96,764

Pro Forma Condensed Consolidated Statements of Income (in thousands of dollars, except per share amounts):

1994	WWP	SPR	PRO FORMA (unaudited)
Operating revenues	$670,765	$626,312	$1,297,077
Operating expenses	515,307	498,860	1,014,167
Income from operations	155,458	127,452	282,910
Income from continuing operations before preferred dividends	77,197	60,300	137,497
Income available for common stock	68,541	52,366	120,907
Average common shares outstanding	53,538	29,219	95,613
Earnings per share	$1.28	$1.79	$1.26

1993	WWP	SPR	PRO FORMA (unaudited)
Operating revenues	$640,599	$528,075	$1,168,674
Operating expenses	479,749	415,286	895,035
Income from operations	160,850	112,789	273,639
Income from continuing operations before preferred dividends	82,776	53,151	135,927
Income available for common stock	74,441	44,890	119,331
Average common shares outstanding	51,616	26,895	90,345
Earnings per share	$1.44	$1.67	$1.32

1992

	WWP	SPR	PRO FORMA (unaudited)
Operating revenues	$557,758	$481,810	$1,039,568
Operating expenses	407,133	394,568	801,701
Income from operations	150,625	87,242	237,867
Income from continuing operations before preferred dividends	72,267	33,789	106,056
Income available for common stock	65,450	28,149	93,599
Average common shares outstanding	49,550	25,709	86,571
Earnings per share	$1.32	$1.09	$1.08

NOTE 16. PROPERTY, PLANT AND EQUIPMENT

The year-end balances of the major classifications of property, plant and equipment are detailed in the following table (dollars in thousands):

	At December 31,	
	1994	1993
Electric:		
Production	$ 678,356	$ 643,437
Transmission	238,912	228,180
Distribution	458,867	433,003
CWIP and other	101,863	104,689
Electric total	1,477,998	1,409,309
Natural Gas:		
Underground storage	14,946	14,686
Transmission	3,090	3,060
Distribution	253,830	226,894
CWIP and other	45,108	32,863
Natural Gas total	316,974	277,503
Common plant (including CWIP)	34,624	36,157
Total utility	1,829,596	1,722,969
Non-utility	56,466	46,387
Total	$1,886,062	$1,769,356

Sch. 19	MONTANA PLANT IN SERVICE (ASSIGNED AND ALLOCATED)			
	Account Number and Title	Last Year	This Year	% Change
1				
2	Intangible Plant			
3				
4	301 Organization			
5	302 Franchies and Consents	193,078	193,078	0.00
6	303 Miscellaneous Intangible Plant	52,147	22,283	(57.27)
7				
8	TOTAL Intangible Plant	245,225	215,361	(12.18)
9				
10	Production Plant			
11				
12	**Steam Production**			
13				
14	310 Land & Land Rights	1,304,594	1,306,668	0.16
15	311 Structures & Improvements	99,019,372	99,067,221	0.05
16	312 Boiler Plant Equipment	114,046,452	114,127,518	0.07
17	313 Engines & Engine Driven Generators			
18	314 Turbo Generator Units	24,164,354	25,538,994	5.69
19	315 Accessory Power Plant Equipment	13,405,701	13,418,852	0.10
20	316 Miscellaneous Power Plant Equipment	11,941,356	12,146,327	1.72
21				
22	TOTAL Steam Production Plant	263,881,829	265,605,580	0.65
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	0	0	0.00
34				
35	**Hydraulic Production**			
36				
37	330 Land and Land Rights	37,917,514	37,917,514	0.00
38	331 Structures and Improvements	10,146,451	10,290,197	1.42
39	332 Resevoirs, Dams and Waterways	30,756,777	30,765,424	0.03
40	333 Water Wheels, Turbines and Generators	30,436,161	30,436,161	0.00
41	334 Accessory Electric Eqipment	2,494,420	3,165,127	26.89
42	335 Miscellaneous Power Plant Equipment	1,496,389	1,653,387	10.49
43	336 Road, Railroads & Bridges	88,694	88,694	0.00
44				
45	TOTAL Hydraulic Production Plant	113,336,406	114,316,504	0.86
46				
47				
48				
49				
50				
51				
52				

Sch. 19	MONTANA PLANT IN SERVICE (ASSIGNED AND ALLOCATED)		
Account Number and Title	Last Year	This Year	% Change
Production Plant (con't)			
Other Production			
340 Land & Land Rights			
341 Structures & Improvements			
342 Fuel Holders, Producers & Accessories			
343 Prime Movers			
344 Generators			
345 Accessory Electric Equipment			
346 Miscellaneous Power Plant Equipment			
TOTAL Other Production Plant	0	0	0.00
TOTAL Production Plant	377,218,235	379,922,084	0.72
Transmission Plant			
350 Land & Land Rights	883,384	883,384	0.00
352 Structures and Improvements	130,527	130,527	0.00
353 Station Equipment	14,227,946	14,260,552	0.23
354 Towers & Fistures	15,986,603	15,991,563	0.03
355 Poles & Fixtures	6,714,559	6,716,711	0.03
356 Overhead Conductors and Devices	15,696,272	15,699,715	0.02
357 Underground Conduit			
358 Underground Conductors & Devices			
359 Roads & Trails	367,477	367,477	0.00
TOTAL Transmission Plant	54,006,768	54,049,929	0.08
Distribution Plant			
360 Land & Land Rights	15,881	15,881	0.00
361 Structures & Improvements	133,565	133,565	0.00
362 Station Equipment			
363 Storage Battery Equipment	8,955	8,955	0.00
364 Poles, Towers and Fixtures	6,934	6,676	(3.72)
365 Overhead Conductors & Devices	46	46	0.00
366 Underground Conduit	637	637	0.00
367 Underground Conductors & Devices	897	897	0.00
368 Line Transformfers	128	128	0.00
369 Services	29	29	0.00
370 Meters			
371 Installations on Customers' Premises			
372 Leased Property on Customers' Premises			
373 Street Lighting and Signal Systems			
TOTAL Distribution Plant	167,072	166,814	(0.15)

Sch. 19	MONTANA PLANT IN SERVICE (ASSIGNED AND ALLOCATED)			
	Account Number and Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvement			
6	391 Office Furniture & Equipment	15,694	0	0.00
7	392 Transportation Equipment	102,366	0	(100.00)
8	393 Stores Equipment			
9	394 Tools, Shop and Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment	220,920	0	(100.00)
12	397 Communications Equipment	2,381,641	0	(100.00)
13	398 Miscellaneous Equipment	290	0	(100.00)
14	399 Other Tangible Property			
15				
16	TOTAL General Equipment	2,720,911	0	(100.00)
17				
18	TOTAL Electric Plant in Service	434,358,211	434,354,188	0.00

Sch. 20	MONTANA DEPRECIATION SUMMARY		Accumulated Depreciation		Current
	Functional Plant Classification	Plant Cost	Last Year Bal.	This Year Bal.	Avg. Rate
1		(Depreciable)			
2	Steam Production (Colstrip Plant)	264,298,912	72,240,075	80,182,560	28.84
3	Nuclear Production				
4	Hydro Production (Noxon Plant)	104,492,436	7,029,738	7,590,776	7.00
5	Other Production				
6	Transmission Not Available				
7	Distribution Not Available				
8	General Not Available				
9	**TOTAL**	368,791,348	79,269,813	87,773,336	22.65

Sch 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)			
	Account	Last Year Bal.	This Year Bal.	% Change
1				
2	151 Fuel Stock	604,999	329,434	(45.55)
3	152 Fuel Stock Expenses Undistributed	0	0	
4	153 Residuals			
5	154 Plant Materials & Operating Supplies			
6	Assigned to Construction (Estimated)			
7	Assigned to Operation and Maintenance			
8	Production Plant (Estimated)	2,375,807	2,525,297	6.29
9	Transmission Plant (Estimated)			
10	Distribution Plant (Estimated)			
11	Assigned to Other			
12	155 Merchandise	0	0	
13	156 Other Material & Supplies	0	0	
14	157 Nuclear Materials Held for Sale	0	0	
15	163 Stores Expense Undistributed	0	0	
16				
17	TOTAL Materials & Supplies	2,980,806	2,854,731	(4.23)

Sch. 22	MONTANA REGULATORY CAPITAL STRUCTURE & COSTS			
	Commission Accepted - Most Recent	% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number			
2	Order Number			
3				
4	Common Equity			
5	Preferred Stoock	Reference is made to Schedule 27		
6	Long Term Debt			
7	Other			
8	TOTAL			
9				
10	Actual at Year End (Utility Only 12/31/93)			
11				
12	Common Equity			
13	Preferred Stock			
14	Long Term Debt			
15	Other			
16	TOTAL			

Sch. 23 STATEMENT OF CASH FLOWS

	Description	This Year	Last Year	% Change
1				
2	Increase/(decrease) in Cash and Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	77,196,839	82,776,035	(6.74)
6	Depreciation	42,386,694	42,263,357	0.29
7	Amortization	24,127,608	21,448,862	12.49
8	Deferred Income Taxes - Net	15,688,601	9,704,256	61.67
9	Investment Tax Credits - Net	(97,836)	(97,847)	(0.01)
10	Change in Operating Receivables - Net	(7,746,749)	(1,407,340)	450.45
11	Change in Materials, Supplies & Inventories - Net	(797,103)	(2,001,065)	(60.17)
12	Change in Operating Payable & Accrued Liabilities - Net	2,388,060	5,828,574	(59.03)
13	Allowance for Funds Used During Construction (AFUDC)	(1,261,256)	(1,666,118)	(24.30)
14	Change in Assets and Liabilities - Net			
15	Other Operating Activities (explained on attached page)	(17,428,422)	(15,217,230)	14.53
16	Net Cash Provided by/(Used in) Operating Activities	134,456,436	141,631,484	(5.07)
17				
18	**Cash Inflows/Outflows From Investment Activities**			
19	Construction/Acquisition of Property, Plant and Related Equipment	(119,989,151)	(107,677,013)	(11.43)
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets			
23	Investment In and Advances To Affiliates			
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	(34,637,115)	(33,820,465)	(2.41)
27	Net Cash Provided by/(used in) Investing Activities	(154,626,266)	(141,497,478)	(9.28)
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	88,000,000	250,000,000	64.80
32	Preferred Stock	0	0	
33	Common Stock	25,994,690	36,405,617	28.60
34	Other: Accounts Receivable Sale	0	0	
35	Net Increase (Decrease) in Short-Term Debt	(10,000,749)	64,000,749	115.63
36	Other: Notes Receivable-ESOP	488,750	432,750	(12.94)
37	Payment for Retirement of:			
38	Long-Term Debt	(7,500,000)	(270,000,000)	97.22
39	Preferred Stock	0	0	
40	Common Stock			
41	Other:			
42	Net Decrease in Short-Term Debt	(1,169,267)	(12,325,475)	90.51
43	Dividends on Preferred Stock	(8,486,025)	(8,503,780)	0.21
44	Dividends on Common Stock	(66,487,171)	(64,208,970)	(3.55)
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	20,840,228	(4,199,109)	(596.30)
47				
48	**Net Increase/Decreses in Cash and Cash Equivalents**	670,398	(4,065,103)	(116.49)
49	**Cash and Cash Equivalents at Beginning of Year**	(3,901,328)	163,775	(2,482.13)
50	**Cash and Cash Equivalents at End of Year**	(3,230,930)	(3,901,328)	(17.18)

Sch. 23	STATEMENT OF CASH FLOWS			
	Description	This Year	Last Year	% Change
1				
2	**Detail of Lines 15 and 26**			
3				
4	**Line 15: Other Operating Activities:**			
5	Undistributed Earnings of Subsidiary Companies	(13,844,117)	(13,393,041)	(3.37)
6	Idaho Accretion Income	(348,833)	(388,721)	10.26
7	Change in Dividend Declared	(227,764)	284,750	179.99
8	Non-Monetary Power Transactions	110,496	(321,207)	134.40
9	Regulatory gas cost and power cost adjustment	6,364,731	(7,624,455)	183.48
10	Other Changes-Net	(9,482,935)	6,225,444	252.33
11	Total Line 15	(17,428,422)	(15,217,230)	(14.53)
12				
13				
14	**Line 26: Other Investing Activities**			
15	Additions in Non-Utility Plant	102,443	(302,077)	133.91
16	Other Capital Requirements	(21,158,396)	(30,215,429)	29.97
17	Dividends Received from Subsidiary Companies	7,200,000	0	
18	Changes in Noncurrent Balance Sheet Accounts	(17,679,608)	(1,147,620)	(1,440.55)
19	Other Special Funds	(3,101,554)	(2,155,339)	(43.90)
	Total Line 26	(34,637,115)	(33,820,465)	(2.41)

Sch.24 **LONG TERM DEBT**

	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	First Mortgage Bonds								
3	4 5/8 Series	3/1/65	3/1/95	10,000,000	9,911,403	10,000,000	4.68%	465,453	4.70%
4	7 1/8 Series	12/1/89	12/1/13	66,700,000	63,614,202	66,700,000	7.54%	4,935,819	7.76%
5	7 2/5 Series	12/1/89	12/1/16	17,000,000	16,418,069	17,000,000	7.70%	1,295,140	7.89%
6									
7	6% Pollution Control	7/1/93	12/1/23	4,100,000	3,913,000	4,100,000	6.34%	259,924	6.53%
8									
9	Secured Medium Term Notes Ser. A	Var.	Var.	250,000,000	248,374,625	250,000,000	7.39%	18,478,590	7.44%
10	Secured Medium Term Notes Ser. B	Var.	Var.	63,000,000	62,667,750	63,000,000	8.64%	5,440,674	8.68%
11									
12									
13									
14									
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29									
30									
31									
32									
33	TOTAL Year End			410,800,000	404,899,049	410,800,000			

Sch.25	PREFERRED STOCK									
	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Dividend Rate	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2	Flexible Auction									
3	Non-Redeemable:									
4	Series "J"	Var.	500	$100,000	-	47,463,854	Var.	50,000,000	Var.	Var.
5										
6	Redeemable:									
7	Series "I"	4/26/90	500,000	$100	-	46,505,987	8.625%	50,000,000	4,312,500	9.27%
8	Series "K"	9/15/92	350,000	$100	-	32,910,815	6.950%	35,000,000	2,432,500	7.39%
9										
10										
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29										
30										
31										
32										
33	TOTAL					126,880,656		135,000,000		

Sch.26

COMMON STOCK

Month	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
January	52,805,437	12.22				18.875	17.375	14.24
February	52,881,961	12.05				18.500	16.625	13.69
March	53,041,773	12.25	.46	.31		17.875	16.875	13.90
April	53,228,736	12.31				17.875	16.750	14.31
May	53,283,966	12.08				17.875	14.750	12.91
June	53,456,903	12.23	.25	.31		16.000	14.250	11.69
July	53,643,462	11.93				15.375	13.875	12.40
August	53,727,084	11.98				16.250	15.000	12.20
September	53,886,069	12.06	.11	.31		15.375	14.250	11.69
October	54,050,100	12.15				14.875	14.250	12.29
November	54,124,461	11.93				14.750	13.750	13.20
December	54,298,488	12.21	.46	.31		14.125	13.625	10.74
TOTAL Year End			1.28	1.24	3.1%	13.175		10.74

Sch. 27 **MONTANA EARNED RATE OF RETURN**

Line	Account	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	Material and 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**		NOT MEANINGFUL	
23					
24		**Rate of Return on Average Equity**		NOT MEANINGFUL	
25					
26		Major Normalizing Adjustments & Commission			
27		Ratemaking Adjustments to Utility Operations			
28					
29					
30					
31		The Washington Water Power Company has 19 customers with 1994 revenues amounting to $5,294,164 in the State			
32		of Montana. Rates charged were based on the Company's last rate order from the Idaho Public Utilities Commission			
33		and accepted by the Montana Commission. The company does not calculate seperate rate of return for the Montana			
34		jurisdiction.			
35					
36					
37					
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49					
50		**Adjusted Rate of Return on Average Rate Base**			
51					
52		**Adjusted Rate of Return on Average Equity**			

Sch. 28	MONTANA COMPOSITE STATISTICS		
		Description	Amount
1			
2		Plant (Intrastate Only)	
3			
4	101	Plant in Service	434,358,211
5	107	Construction Work in Progress	1,621,735
6	114	Plant Acquisition Adjustments	-
7	105	Plant Held for Future Use	-
8	154,156	Materials & Supplies	2,854,731
9		(Less):	
10	108,111	Depreciation & Amortization Reserves	87,773,336
11	252	Contributions in Aid of Construction	
12			
13		NET BOOK COSTS	351,061,341
14			
15			
16		Revenues & Expenses	
17			
18	400	Operating Revenues	5,294,164
19			
20	403 - 407	Depreciation & Amortization Expenses	8,503,523
21	409	Federal Income Taxes (State Only, Federal Not Allocated)	802,078
22	408	Other Taxes	8,884,963
23		Other Operating Expenses	44,551,196
24		TOTAL Operating Expenses	62,741,760
25			
26		Net Operating Income	(57,447,596)
27			
28	415 - 421.1	Other Income	-
29	421.2 - 426.5	Other Deductions	-
30			
31		NET INCOME(LOSS)	(57,447,596)
32			
33			
34		Customers (Intrastate Only)	
35			
36		Year End Average:	
37		Residential	11
38		Commercial	1
39		Industrial	
40		Other	7
41			
42		TOTAL NUMBER OF CUSTOMERS	19
43			
44			
45		Other Statistics (Intrastate Only)	
46			
47		Average Annual Residential Use (Kwh)	15,318
48		Average Annual Residential Cost per (kwh) (Cents) *	4.57
49		* Avg annual cost = {(cost per Kwh x annual use) + (mo. svc chrg x 12)}/annual use	
50		Average Residential Monthly Bill	58.31
51		Gross Plant per Customer	39,487,110

Sch.29 **MONTANA CUSTOMER INFORMATION**

	City / Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1						
2	Noxon, Montana		11	1	6	18
3						
4	Hot Springs, Montana (Secondary Sales for Resale to Montana Power Company)				1	1
5						
6						
7						
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32						
33	TOTAL Montana Customers		11	1	7	19

Sch. 30	MONTANA EMPLOYEE COUNTS			
	Department	Year Beginning	Year End	Average
1				
2	Noxon Generating Station	14	17	15.5
3				
4				
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50				
51				
52				
53	TOTAL Montana Employees	15	14	14.5

Sch. 31	MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1	1995 Construction Budget		
3	Colstrip, Montana		
4	Colstrip Generating Station--Various Additions		2,826,200
6	Noxon, Montana		
7	Noxon Rapids Generating Station, Noxon - Upgrade Cooling System		70,316
53	TOTAL		2,826,200

Sch. 32		TOTAL SYSTEM & MONTANA PEAK AND ENERGY				
		SYSTEM				
		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non - Requirements Sales for Resale
1	Jan.	31	900	1294	991,904	272,900
2	Feb.	8	800	1516	977,438	284,861
3	Mar.	7	800	1194	890,609	230,603
4	Apr.	4	1100	1118	836,961	245,717
5	May	11	1400	1046	890,739	314,719
6	Jun.	22	1600	1198	818,660	218,802
7	Jul.	25	1700	1270	783,534	139,080
8	Aug.	3	1400	1226	801,579	170,411
9	Sep.	7	1600	999	760,091	217,430
10	Oct.	31	800	1178	873,836	257,079
11	Nov.	22	800	1361	985,521	261,097
12	Dec.	5	1800	1436	1,018,718	256,463
13	TOTAL				10,629,590	2,869,162
		MONTANA				
		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non - Requirements Sales for Resale
14	Jan.	Not Available	Not Available	Not Available	397	370
15	Feb.	"		"	1,622	1,600
16	Mar.	"	"	"	9,675	9,650
17	Apr.	"	"	"	10,610	10,585
18	May	"	"	"	2,556	2,540
19	Jun.	"	"	"	10,110	10,095
20	Jul.	"	"	"	1,652	1,635
21	Aug.	"	"	"	2,181	2,165
22	Sep.	"	"	"	10,831	10,815
23	Oct.	"	"	"	9,879	9,855
24	Nov.	"	"	"	2,968	2,940
25	Dec.	"	"	"	11,376	11,350
26	TOTAL				73,857	73,600

Sch. 33	TOTAL SYSTEM Sources & Disposition of Energy			
	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (net of Station Use)			
2	Steam	3,399,745	Sales to Ultimate Consumers	
3	Nuclear	0	(Less Interdepartmental)	7,239,597
4	Hydro - Conventional	2,904,473		
5	Hydro - Pumped Storage	0	Requirements: Sales	
6	Other (Turbines)	26,884	for Resale	17,724
7	(Less) Energy for Pumping	0		
8	**NET Generation**	6,331,102	Non - Requirements: Sales	
9	Purchases	4,322,640	for Resale	2,869,162
10	Power Exchanges			
11	Received	1,047,725	Energy Furnished	
12	Delivered	(1,094,688)	Without Charge	0
13	**NET Exchanges**	(24,152)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	3,093,964	Electric Utility	14,203
16	Delivered	3,093,964		
17	**Net Transmission Wheeling**	0	Total Energy Losses	488,904
18	Transmission Lossed by Others	0		
19	**TOTAL**	10,629,590	**TOTAL**	10,629,590

Sch. 34	SOURCES OF ELECTRIC ENERGY				
	Type	Plant Name	Location	Annual Peak	Annual Energy
1	Washington				
2	Thermal	Centralia	Centralia, WA	205.0	1,429,565
3	Thermal	Kettle Falls	Kettle, Falls, WA	50.0	329,841
4	Hydro	Little Falls	Ford, WA	36.0	164,826
5	Hydro	Long Lake	Ford, WA	72.0	359,945
6	Hydro	Meyers Falls	Colville, WA	1.3	6,123
7	Hydro	Monroe Street	Spokane, WA	13.0	71,812
8	Hydro	Nine Mile	Spokane, WA	25.0	79,618
9	Hydro	Upper Falls	Spokane, WA	10.2	68,462
10	Combustion Turbine	Northeast	Spokane, WA	65.0	5,691
11					
12	Total Washington				2,515,883
13					
14					
15	Idaho				
16	Hydro	Cabinet Gorge	Clark Fork, ID	236.0	827,764
17	Hydro	Post Falls	Post Falls, ID	18.0	73,192
18	Combustion Turbine	Rathdrum (See Note 1)	Rathdrum, ID	165.0	21,193
19					922,149
20	Total Idaho				
21					
22					
23	Montana				
24	Thermal	Colstrip #3 & #4	Colstrip, MT	218.0	1,640,339
25	Hydro	Noxon	Thompson Falls, MT	534.0	1,252,731
26					2,893,070
27	Total Montana				
28					
29					
30					
31					
32					
33	Total System				6,331,102
34					
35					
36	Note 1: Reflects Test Power in 1994				
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	TOTAL				6,331,102

Sch.35 MONTANA CONSERVATION AND DEMAND SIDE MAMAGEMENT PROGRAMS

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1							
2	Not Applicable						
3							
4							
5							
6							
7							
8							
9							
10							
11							
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33							

Sch.36	MONTANA CONSUMPTION AND REVENUES						
		Operating Revenues		MegaWatt Hours Sold		Avg. No. of Customers	
	Sales of Electricity	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	7,696	10,243	169	218	11	12
2	Commercial - Small	1,424	2,493	21	37	1	3
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large						
6	Interruptible Industrial						
7	Public Street and Highway Lighting						
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Utilities	1,410,623	1,387,834	73,600	104,849	1	1
11	Interdepartmental	4,222	234	67	3	6	
12							
13	TOTAL	1,423,965	1,400,804	73,857	105,107	19	16