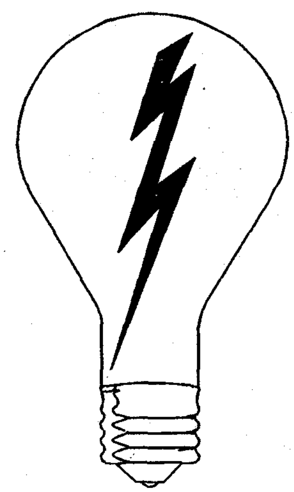
YEAR 1993

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

Check No. 438212

REVISED OCTOBER 20, 1992

TABLE OF CONTENTS

continued on next page

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	484,167
2	J. R. Harvey (1) (2)	E. 1411 Mission Avenue, Spokane, WA 99202	282,917
3	David A. Clack	E. 325 Sprague Avenue, Spokane, WA 99202	17,600
4	Duane B. Hagadone	P.O.Box 6200, Coeur d' Alene, ID 83816	20,400
5	Robert S. Jepson	1 Skidway Village Walk, Suite 201, Savanna, GA 31411	5,660
6	Eugene B. Meyer	3 Plumbridge Lane, Hilton Head Island, SC 29928	38,764
7	General H. Norman Schwarzkopf	400 N. Ashley Street, Suite 3050, Tampa, FL 33602	4,920
8	B. Jean Silver	N. 7102 Audubon Drive, Spokane, WA 99208	20,199
9	Larry A. Stanley	W. 311 32nd Avenue, Spokane, WA 99203	20,346
10	R. John Taylor	P.O. Box 538, Lewiston ID 83501	21,745
11	Eugene Thompson	3307 Pinecrest Road, Moscow, ID 83843	25,247
12			
13			
14	(1) Mr Redmond and Mr Harvey are Chairman of the Board and Chief Executive Officer; and President and Chief		
15	Operating Officer respectively. All amounts shown reflect annual remuneration.		
16			
17	(2) Mr. Harvey retired from the Washington Water Power Company on February 1, 1994.		
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Sch. 3

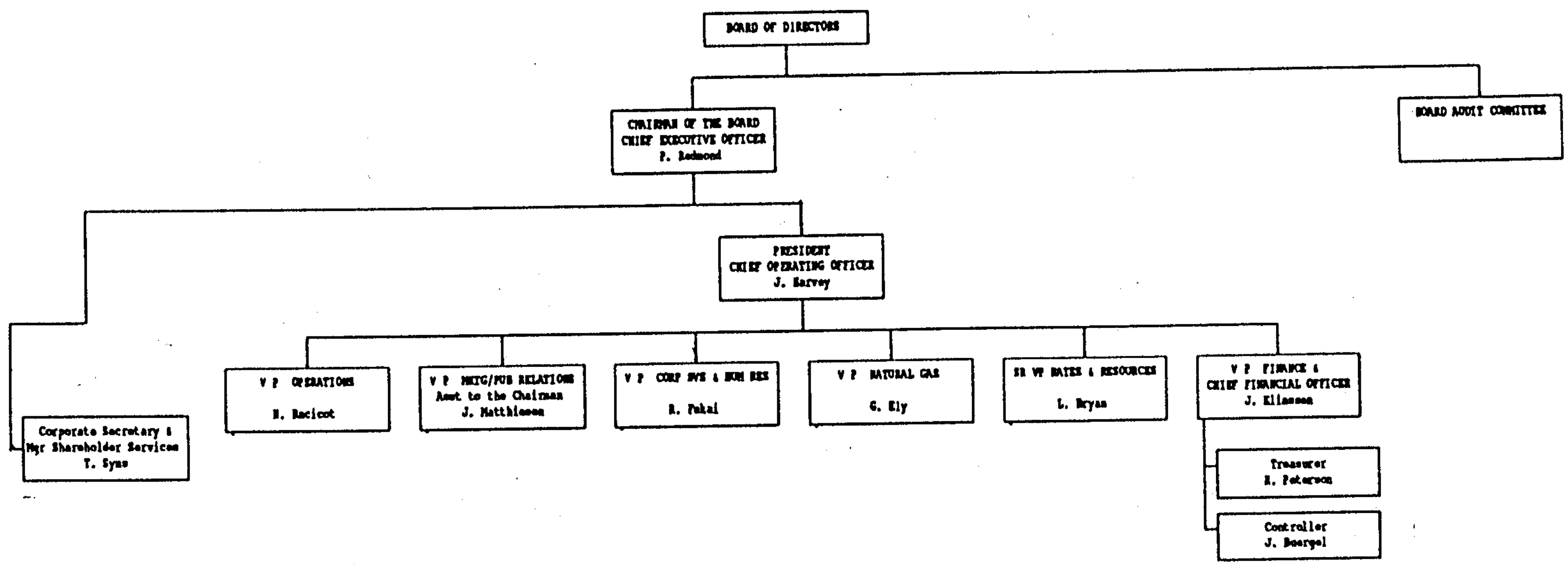
OFFICERS

Title	Department Supervised	Name
Chairman of the Board and Chief Executive Officer	*	Paul A. Redmond
President and Chief Operating Officer	*	J. R. Harvey * *
Vice President-Finance and Chief Financial Officer	Finance Department	J. E. Eliassen
Senior Vice President	Rates and Resourses	W. L. Bryan
Vice President	Marketing, Public Relations	J. G. Matthisen
Vice President	Corporate Services, Human Resourses	R. D. Fuki
Vice President	Operations	N. J. Racicot
Treasurer	Funds Management, Tax and Payroll, Corporate Finance and Investor Relations	R. R. Peterson
Controller	Corporate Accounting, Plant Accounting, Rates	J. W. Buergel
Corporate Secretary	Shareholder Services	T. L. Syms

* See organization chart attached

* * Mr. Harvey retired from the Washington Water Power Company on February 1, 1994.

WASHINGTON WATER POWER
ORGANIZATIONAL CHART
AS OF OCTOBER 1992



Sch. 4	CORPORATE STRUCTURE			
	Subsidiary/Company Name	Line of Business	Earnings	% of Total
1				
2	Pentzer Corporation	Parent Company of all of the Company's Subsideries, except	12,675,887	95.6
3		Washington Irrigation and Development Company and		
4		WP Finance.		
5				
6	Washington Irrigation and	Non-Operating	681,402	5.1
7	Development Company			
8				
9	WP Finance	Non-Operating	0	0.0
10				
11	Limestone	Non-Operating	(91,559)	(0.7)
12				
13				
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53			13,265,730	100.0

Sch. 5 **CORPORATE ALLOCATIONS**

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1						
2	Not Applicable					
3						
4						
5						
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34						
35	TOTAL					

Sch. 6

ASSET SALES, TRANSFERS & RETIREMENTS AFFECTING MT UTILITY

	Plant Description	Plant Account Number	Work Order Number	Item Ever Rate Based (Y or N)	Trans. Date	Trans. Type (S, T, R)	Mortgage Relese (Y or N)	Trans. Amount (OOO)	Gain / Loss (OOO)
1									
2	None								
3									
4									
5									
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Sch. 7

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. 8

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					
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Sch. 9		MONTANA UTILITY INCOME STATEMENT			
		Account Number & Title	Last Year	This Year	% Change
1	400	Operating Revenues	2,062,617	3,144,590	52.46
2					
3		Operating Expenses			
4	401	Operating Expenses	28,551,678	29,427,170	3.07
5	402	Maintenance	5,205,554	6,151,124	18.16
6	403	Depreciation Expense	8,545,149	8,558,453	0.16
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	8,145,463	9,108,557	11.82
12	409.1	Income Taxes - Federal	None or not allocated		
13		- Other (State of Montana)	853,580	667,886	(21.75)
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	51,301,424	53,913,190	5.09
21					
22		NET UTILITY OPERATING INCOME	(49,238,807)	(50,768,600)	3.11

Sch. 10		MONTANA REVENUES			
		Account Number and Title			
1		Sales of Electricity			
2	440	Residential	10,487	10,243	(2.33)
3	442	Commercial & Industrial - Small	11,455	2,493	(78.24)
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	100.00
9					
10		TOTAL Sales of Electricity	21,942	12,970	(40.89)
11	447	Sales for Resale	887,581	1,387,834	56.36
12					
13		TOTAL Sales to Ultimate Consumers	909,523	1,400,804	54.02
14	449.1	(Less) Provision for Rate Refunds			
15					
16		TOTAL Revenue Net of Provision for Refunds	909,523	1,400,804	54.02
17		Other Operating Revenue			
18	450	Forfeited Discounts & Late Payment Revenues			
19	451	Miscellaneous Service Revenues			
20	453	Sales of Water & Water Power	13,284	9,158	(31.06)
21	454	Rent for Electric Property	99,676	101,675	2.01
22	455	Interdepartmental Rents			
23	456	Other Electric Revenues	1,040,134	1,632,953	56.99
24					
25		TOTAL Other Operating Revenues	1,153,094	1,743,786	51.23
26					
27		Total Electric Operating Revenue	2,062,617	3,144,590	52.46

Sch. 11	MONTANA OPERATION & MAINTENANCE EXPENSES			
	Account Number & Title	Last Year	This Year	% Change
1				
2	Power Production Expenses			
3				
4	**Steam Power Generation**			
5				
6	Operation			
7	(500) Operation Supervision and Engineering	331,107	329,265	(0.56)
8	(501) Fuel	13,459,161	10,056,035	(25.28)
9	(502) Steam Expenses	1,304,319	1,221,504	(6.35)
10	(503) Steam from Other Sources			
11	(Less) Steam Transferred-Cr.			
12	(505) Electric Expenses	460,482	483,286	4.95
13	(506) Miscellaneous Steam Power Expenses	1,285,305	2,004,889	55.99
14	(507) Rents	2,762	6,521	136.10
15				
16	TOTAL Operation - Steam	16,843,136	14,101,500	(16.28)
17				
18	Maintenance			
19	(510) Maintenance Supervision and Engineering	403,696	389,263	(3.58)
20	(511) Maintenance of Structures	375,032	351,984	(6.15)
21	(512) Maintenance of Boiler Plant	2,156,274	2,780,439	28.95
22	(513) Maintenance of Electric Plant	1,010,431	1,652,437	63.54
23	(514) Maintenance of Miscellaneous Steam Plant	424,658	389,267	(8.33)
24				
25	TOTAL Maintenance - Steam	4,370,091	5,563,390	27.31
26				
27	TOTAL Power Production Expenses-Steam Plant	21,213,227	19,664,890	(7.30)
28				
29	Nuclear Power Generation			
30				
31	Operation			
32	(517) Operation Supervision and Engineering			
33	(518) Fuel			
34	(519) Coolants and Water			
35	(520) Steam Expenses			
36	(521) Steam from Other Sources			
37	(Less) (522) Steam Transferred-Cr.			
38	(523) Electric Expenses			
39	(524) Miscellaneous Nuclear Power Expenses			
40	(525) Rents			
41				
42	TOTAL Operation Nuclear	0	0	
43				
44	Maintenance			
45	(528) Maintenance Supervision and Engineering			
46	(529) Maintenance of Structures			
47	(530) Maintenance of Reactor Plant Equipment			
48	(531) Maintenance of Electric Plant			
49	(532) Maintenance of Miscellaneous Nuclear Plant			
50				
51	TOTAL Maintenance Nuclear	0	0	
52				
53	TOTAL Power Production Expenses-Nuclear Power	0	0	

Sch. 11	MONTANA OPERATION & MAINTENANCE EXPENSES			
	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses - continued			
2	**Hydraulic Power Generation**			
3				
4	Operation			
5	(535) Operation Supervision and Engineering	85,993	58,986	(31.41)
6	(536) Water for Power			
7	(537) Hydraulic Expenses	33,128	7,851	(76.30)
8	(538) Electric Expenses	519,157	458,489	(11.69)
9	(539) Miscellaneous Hydraulic Power Generation Expenses	91,525	81,612	(10.83)
10	(540) Rents	0	48	(100.00)
11				
12	TOTAL Operation - Hydraulic	729,803	606,986	(16.83)
13				
14	Maintenance			
15	(541) Maintenance Supervision and Engineering	3,909	5,796	48.27
16	(542) Maintenance of Structures	50,985	44,005	(13.69)
17	(543) Maintenance of Reservoirs, Dams, and Waterways	26,585	18,561	(30.18)
18	(544) Maintenance of Electric Plant	613,309	380,113	(38.02)
19	(545) Maintenance of Miscellaneous Hydraulic Plant	28,497	17,308	(39.26)
20			465,783	
21	TOTAL Maintenance - Hydraulic	723,285	465,783	(35.60)
22				
23	TOTAL Hydraulic Power Production Expenses	1,453,088	1,072,769	(26.17)
24				
25	**Other Power Generation**			
26				
27	Operation			
28	(546) Operation Supervision and Engineering			
29	(547) Fuel			
30	(548) Generation Expenses			
31	(549) Miscellaneous Other Power Generation Expenses			
32	(550) Rents			
33				
34	TOTAL Operation - Other	0	0	
35				
36	Maintenance			
37	(551) Maintenance Supervision and Engineering	0	0	
38	(552) Maintenance of Structures			
39	(553) Maintenance of Generating and Electric Plant			
40	(554) Maintenance of Miscellaneous Other Power Generation Plant			
41				
42	TOTAL Maintenance - Other	0	0	
43				
44	TOTAL Power Production Expenses-Other Power	0	0	
45				
46	**Other Power Supply Expenses**			
47	(555) Purchased Power	9,901,658	13,628,419	37.64
48	(556) System Control and Load Dispatching			
49	(557) Other Expenses			
50				
51	TOTAL Other Power Supply Expenses	9,901,658	13,628,419	37.64
52				
53	TOTAL Power Production Expenses	32,567,973	34,366,078	5.52

Sch. 11	MONTANA OPERATION & MAINTENANCE EXPENSES			
	Account Number & Title	Last Year	This Year	% Change
1	**TRANSMISSION EXPENSES**			
2	Operation			
3	(560) Operation Supervision and Engineering	22,857	22,400	(2.00)
4	(561) Load Dispatching	13,118	23,448	78.75
5	(562) Station Expenses	63,828	80,625	26.32
6	(563) Overhead Line Expenses	8,108	7,276	(10.26)
7	(564) Underground Line Expenses			
8	(565) Transmission of Electricity by Others	94,611	12	(99.99)
9	(566) Miscellaneous Transmission Expenses			
10	(567) Rents	77,462	101,433	30.95
11				
12	TOTAL Operation - Transmission	279,984	235,194	(16.00)
13	Maintenance			
14	(568) Maintenance Supervision and Engineering	7,456	6,544	(12.23)
15	(569) Maintenance of Structures	11	(12)	(209.09)
16	(570) Maintenance of Station Equipment	41,163	45,770	11.19
17	(571) Maintenance of Overhead Lines	22,583	18,341	(18.78)
18	(572) Maintenance of Underground Lines			
19	(573) Maintenance of Miscellaneous Transmission Plant			
20				
21	TOTAL Maintenance - Transmission	71,213	70,643	(0.80)
22				
23	TOTAL Transmission Expenses	351,197	305,837	(12.92)
24				
25	**DISTRIBUTION EXPENSES**			
26	Operation			
27	(580) Operation Supervision and Engineering			
28	(581) Load Dispatching			
29	(582) Station Expenses	6	700	11,566.67
30	(583) Overhead Line Expenses	0	150	100.00
31	(584) Underground Line Expenses			
32	(585) Street Lighting and Signal System Expenses	0	61	100.00
33	(586) Meter Expenses			
34	(587) Customer Installations Expenses			
35	(588) Miscellaneous Distribution Expenses			
36	(589) Rents			
37				
38	TOTAL Operation - Distribution	6	911	15,083.33
39	Maintenance			
40	(590) Maintenance Supervision and Engineering			
41	(591) Maintenance of Structures	60	0	(100.00)
42	(592) Maintenance of Station Equipment	0	727	100.00
43	(593) Maintenance of Overhead Lines	48	819	1,606.25
44	(594) Maintenance of Underground Lines			
45	(595) Maintenance of Line Transformers			
46	(596) Maintenance of Street Lighting and Signal Systems			
47	(597) Maintenance of Meters	66	0	(100.00)
48	(598) Maintenance of Miscellaneous Distribution Plant			
49				
50	TOTAL Maintenance - Distribution	174	1,546	788.51
51				
52	TOTAL Distribution Expenses	180	2,457	1,265.00
53				

Sch. 11	MONTANA OPERATION & MAINTENANCE EXPENSES			
	Account Number & Title	Last Year	This Year	% Change
2	**CUSTOMER ACCOUNTS EXPENSES**			
3	Operation			
4	(901) Supervision			
5	(902) Meter Reading Expenses			
6	(903) Customer Records and Collection Expenses			
7	(904) Uncollectible Accounts			
8	(905) Miscellaneous Customer Accounts Expenses			
9				
10	TOTAL Customer Accounts Expenses	0	0	
11				
12	**CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**			
13	Operation			
14	(907) Supervision			
15	(908) Customer Assistance Expenses			
16	(909) Informational and Instructional Expenses			
17	(910) Miscellaneous Customer Service and Informational Expenses			
18				
19	TOTAL Cust. Service and Informational Expenses	0	0	
20				
21	**SALES EXPENSES**			
22	Operation			
23	(911) Supervision			
24	(912) Demonstrating and Selling Expenses			
25	(913) Advertising Expenses			
26	(916) Miscellaneous Sales Expenses			
27				
28	TOTAL Sales Expenses	0	0	
29				
30	**ADMINISTRATIVE AND GENERAL EXPENSES**			
31	Operation			
32	(920) Administrative and General Salaries			
33	(921) Office Supplies and Expenses	0	494	100.00
34	(Less) (922) Administrative expenses Transferred-Credit			
35	(923) Outside Services Employed			
36	(924) Property Insurance	69,369	75,216	8.43
37	(925) Injuries and Damages	29,472	35,411	20.15
38	(926) Employee Pensions and Benefits	1,900	655	(65.53)
39	(927) Franchise Requirements			
40	(928) Regulatory Commission Expenses	696,350	742,342	6.60
41	(Less) (929) Duplicate Charges-Cr.			
42	(930.1) General Advertising Expenses			
43	(930.2) Miscellaneous General Expenses	0	42	100.00
44	(931) Rents			
45				
46	TOTAL Operation	797,091	854,160	7.16
47	Maintenance			
48	(935) Maintenance of General Plant	40,791	49,762	21.99
49				
50	TOTAL Administrative and General Expenses	837,882	903,922	7.88
51				
52	TOTAL Electric Operation and Maintenance Expenses	33,757,232	35,578,294	5.39
53				

Sch. 12	MONTANA TAXES OTHER THAN INCOME		
Description of Tax	Last Year	This Year	% Change
Real and Personal Property Tax	8,105,871	8,520,496	5.12
Beneficial Use Tax	(574,709)	0	(100.00)
Kilowatt Hour Tax	609,103	582,584	(4.35)
Unemployment Tax	4,492	4,168	(7.21)
Consumer Council Tax	659	1,266	92.11
Public Commission Tax	47	43	(8.51)
TOTAL MT Taxes other than Income	8,145,463	9,108,557	11.82

Sch. 13 **PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES**

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1					
2					
3	The schedule of Charges for Professional and Other Consultive Services will be filed with the Montana Commission on April 30, 1994,				
4					
5	which is consistant with the filing of FERC Form 2 with other state regulatory agencies. This schedule is a part of those filings.				
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53	TOTAL Payments for Services				

Sch. 14	POLITICAL ACTION COMMITTIES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana
1				
2	POLITICAL ACTION COMMITTIES			
3				
4	Energy Associates			
5	Racicot/Rehberg 1992 Campaign(Debt Retirement)		1,000.00	100.00%
6				
7	Federal-The Washington Water Power Company			
8	The Burns Committee		500.00	100.00%
9				
10				
11	CONTRIBUTIONS			
12				
13	1993 Montana Governor's Inaugural Ball		1,000.00	100.00%
14				
15	Utility Taxpayers Opposing the Sales Tax Committee		45,942.28	100.00%
16				
17	Racicot Inaugural Committee		500.00	100.00%
18				
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53			48,942.28	100.00%

Sch. 15	PENSION COSTS			
	Description	Last Year	This Year	% Change
1				
2	Defined Benefit Plan?	Yes	Yes	
3				
4	Defined Contribution Plan?	No	No	
5				
6	Acturial Cost Method?	Yes	Yes	
7				
8	Is the Plan Overfunded?	Yes	Yes	
9				
10	Accumulated Benefit Obligation	(76,853,000)	(85,368,000)	11.08%
11	Projected Benefit Obligation	(95,446,000)	(104,025,000)	8.99%
12	Fair Value of Plan Assets	118,883,000	126,879,000	6.73%
13				
14	Discount Rate for Benefit Obligations	8.5%	7.5%	
15	Expected Long-Term Return on Assets	9.0%	9.0%	
16				
17	Net Periodic Pension Cost:			
18	Service Cost	2,846,000	3,150,000	10.68%
19	Interest Cost	7,390,000	7,771,000	5.16%
20	Return on Plan Assets	(12,257,000)	(15,108,000)	23.26%
21	Amortization of Transition Amount	886,000	3,717,000	319.53%
22	Amortization of Gains or Losses			
23	Total Net Periodic Pension Cost	(1,135,000)	(470,000)	(58.59%)
24				
25	Minimum Required Contribution			
26	Actual Contribution			
27	Maximum Amount Deductible			
28	Benefit Payments	5,822,000	6,004,000	3.13%
29				
30	Montana Intrastate Costs:	Not Available by State		
31	Pension Costs			
32	Pension Costs Capitalized			
33	Accumulated Pension Asset (Liability) at end of year			
34				
35	Number of Company Employees:			
36	Covered by the Plan	1961	2217	13.05%
37	Not Covered by the Plan			
38	Active	1341	1326	(1.12%)
39	Retired/Survivors	509	642	26.13%

Sch. 16 **OTHER POST EMPLOYMENT BENEFITS (OPEBS)**

	Description	Last Year	This Year	% Change
1	General Information			
2				
3	Assumptions:			
4	Discount Rate for Benefit Obligations	8.5	7.5	
5	Expected Long-Term Return on Assets	0	0	
6	Medical Cost Inflation Rate	11%	8.25	
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)	35,369,000	39,594,000	11.95
23	Fair Value of Plan Assets	823,000	636,000	(22.72)
24	List the amount funded through each type of funding:			
25	VEBA	823,000	636,000	(22.72)
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:(Please Note Correction to 1992).			
37	Service Cost	0	1,156,000	100.00
38	Interest Cost	0	3,006,000	100.00
39	Return on Plan Assets			
40	Amortization of Transition Obligation	0	1,769,000	100.00
41	Amortization of Gains and Losses			
42	Total Net Periodic Post Retirement Benefit Cost	0	5,931,000	100.00
43				
44	Benefit Cost Expensed			
45	Benefit Cost Capitalized			
46	Benefit Payments			
47				
48	Number of Company Employees:			
49	Covered by the Plan	1,961	2,217	13.05
50	Not Covered by the Plan			
51	Active	1,341	1,326	(1.12)
52	Retired/Spouses covered by the Plan	620	642	3.55
53				

	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. 17 **TOP TEN MONTANA COMPENSATED EMPLOYES (ASSIGNED OR ALLOCATED)**

	Name/Title	Base Salary*	Bonuses	Other	Total
1	P. J. Aketpy Station Mechanic-Noxon	54,867	216		55,083
2	J. G. Hanna Station Electrician-Noxon	52,565	214		52,779
3	D. W. Thomason Journeyman Operator-Noxon	49,465	236		49,701
4	C. F. Webly Journeyman Operator-Noxon	49,244	221		49,465
5	P. A. Kelly Journeyman Operator-Noxon	48,358	221		48,579
6	M. J. Bonney Journeyman Operator-Noxon	46,290	149		46,439
7	W. A. Maxvill, Jr. Journeyman Operator-Noxon	45,180	217		45,397
8	J. L. Garner Journeyman Operator-Noxon	44,793	219		45,012
9	R. G. Robbins Journeyman Operator-Noxon	44,519	214		44,733
10	T. E. Lampshire Journeyman Operator-Noxon	44,301	216		44,517
	*Includes overtime where applicable.				

Sch. 18	BALANCE SHEET			
	Account Title	Last Year	This Year	% Change
1	Assets and Other Debits			
2	**Utility Plant**			
3				
4	101 Electric/Gas Plant in Service	1,560,411,029	1,640,479,263	5.13
5	101.1 Property Under Capital Leases			
6	102 Electric Plant Purchased or Sold			
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	32,739,289	55,190,943	68.58
11	108 (Less) Accumulated Depreciation	(424,294,941)	(459,676,497)	8.34
12	111 (Less) Accumulated Amortization	(4,354,870)	(6,243,790)	43.37
13	114 Electric/Gas Plant Acquisition Adjustment	28,350,517	27,299,028	(3.71)
14	115 (Less) Accum. Amortization of Gas Acquisition Adjustment	(1,698,315)	(3,056,967)	80.00
15	120 Nuclear Fuel			
16	TOTAL Utility Plant	1,191,152,709	1,253,991,980	5.28
17				
18	**Other Property & Investments**			
19				
20	121 Nonutility Property	2,776,135	3,078,212	10.88
21	122 (Less) Accum. Depr. & Amort. for Nonutility Property	(668,574)	(53,086)	(92.06)
22	123 Investments in Associated Companies			
23	123.1 Investments in Subsidiary Companies	79,615,886	93,099,743	16.94
24	124 Other Investments	117,940,658	109,275,716	(7.35)
25	125 Special Funds	6,745,857	9,203,272	36.43
26	TOTAL Other Property and Investments	206,409,962	214,603,857	3.97
27				
28	**Current & Accrued Assets**			
29				
30	131 Cash	59,878	(4,018,634)	(6,811.37)
31	132-134 Special Deposits		10,000	100.00
32	135 Working Funds	103,897	107,306	3.28
33	136 Temporary Cash Investments	0		
34	141 Notes Receivable	117,701	16,692	(85.82)
35	142 Customer Accounts Receivable	24,607,087	30,139,880	22.48
36	143 Other Accounts Receivable	1,351,630	2,147,485	58.88
37	144 (Less) Accum. Provision for Uncollectible Accounts	(1,389,708)	(1,341,448)	(3.47)
38	145 Notes Receivable - Associated Companies			
39	146 Accounts Receivable - Associated Companies	3,769,575	(122,621)	(103.25)
40	151 Fuel Stock	4,933,418	4,201,135	(14.84)
41	152 Fuel Stock Expenses Undistributed			
42	153 Residuals			
43	154 Plant Materials and Operating Supplies	9,726,195	10,537,110	8.34
44	155 Merchandise			
45	156 Other Material Supplies	58,670	80,752	
46	157 Nuclear Materials Held for Sale			
47	163 Stores Expense Undistributed	(188,642)	(92,435)	(51.00)
48	164-165 Gas Storage Accounts and Prepayments	4,608,505	5,764,383	25.08
49	171 Interest & Dividends Receivable	52,619	72,710	38.18
50	172 Rents Receivable	897,302	849,721	(5.30)
51	173 Accrued Utility Revenues			
52	174 Miscellaneous Current and Accrued Assets	3,565,659	3,192,247	(10.47)
53	TOTAL Current and Accrued Assets	52,273,786	51,544,283	(1.40)

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	4,719,661	4,868,912	3.16
7	182.1	Extraordinary Property Loses			
8	182.2	Unrecovered Plant & Regulatory Study Costs	7,477,218	4,828,707	(35.42)
8A	182.3	Other Regulatory Assets		181,239,980	100.00
9	183	Preliminary Survey & Investigation Charges	9,773,176	9,760,431	(0.13)
10	184	Clearing Accounts	(850,697)	(591,217)	(30.50)
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	29,454,141	51,168,092	73.72
13	187	Deferred Losses from Disposition of Utility Plant			
14	188	Research Development & Demonstration Expenditures	5,817	0	(100.00)
15	189	Unamortized Loss on Reacquired Debt	17,191,957	26,176,173	52.26
16	190-191	Accum. Def. Inc. Taxes & Unrecovered Purch. Gas Costs	27,081,406	35,657,568	31.67
17		TOTAL Deferred Debits	94,852,679	313,108,646	230.10
18					
19		TOTAL Assets & Other Debits	1,544,689,136	1,833,248,766	18.68

		Account Title	Last Year	This Year	% Change
20					
21		Liabilities and Other Credits			
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	508,202,892	544,608,509	7.16
26	202	Common Stock Subscribed	135,000,000	135,000,000	0.00
27	204	Preferred Stock Issued			
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	(9,622,923)	(9,897,522)	2.85
33	215	Appropriated Rertained Earnings	45,048,228	42,434,863	(5.80)
34	216	Unappropriated Retained Earnings	56,595,603	69,988,644	23.66
35	217	(Less) Reacquired Capital Stock			
36		TOTAL Proprietary Capital	735,223,800	782,134,494	6.38
37					
38	**Long Term Debt**				
39					
40	221	Bonds	297,800,000	322,800,000	8.39
41	222	(Less) Reacquired Bonds			
42	223	Advances From Associated Companies			
43	224	Other Long Term Debt	299,280,043	318,305,530	6.36
44	225	Unamortized Premium on Long Term Debt	103,267	0	(100.00)
45	226	(Less) Unamort. Discount on Long Term Debt (Dr.)	(1,624,023)	(1,458,634)	(10.18)
46		TOTAL Long Term Debt	595,559,287	639,646,896	7.40

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	936,226	0	(100.00)
7	228.1	Accumulated Provision for Property Inurance			
8	228.2	Accumulated Provision for Injuries & Damages	1,437,593	1,464,034	1.84
9	228.3	Accumulated Provision for Pensions & Benefits		3,981,000	100.00
10	228.4	Accmulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12		TOTAL Other Noncurrent Liabilities	2,373,819	5,445,034	129.38
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	27,524,989	33,866,889	23.04
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies			
20	235	Customer Deposits	931,667	863,024	(7.37)
21	236	Taxes Accrued	17,656,289	20,144,857	14.09
22	237	Interest Accrued	12,768,996	10,045,865	(21.33)
23	238	Dividends Declared	284,750	0	
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	571,950	646,581	13.05
27	242	Miscellaneous Current & Accrued Liabilities	11,639,956	12,737,855	9.43
28	243	Obligations Under Capital Leases - Current	1,460,867	636,536	(56.43)
29		TOTAL Current & Accrued Liabilities	72,839,464	78,941,607	8.38
30					
31	**Deferred Credits**				
32					
33	252	Customes Advances for Construction	3,426,162	2,655,506	(22.49)
34	253	Other Deferred Credits	13,294,291	11,182,175	(15.89)
35	255	Accumulated Deferred Investment Tax Credit	2,554,099	2,456,252	(3.83)
36	256	Deferred Gains from Disposition of Utility Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	119,418,214	310,786,802	160.25
39		TOTAL Deferred Credits	138,692,766	327,080,735	135.83
40					
41		TOTAL Liabilities & Other Credits	1,544,689,136	1,833,248,766	18.68

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 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 accounting requirements of FERC as set forth in these financial statements differ from generally accepted accounting principles in that the Company accounts for its investment in majority owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of those subsidiaries. The Company is not presenting statements of retained earnings and cash flows for the years 1992 and 1993 as would be required under generally accepted accounting principles.

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.

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 1993, 1992 and 1991. 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. 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.

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 2.68% in 1993, 2.37% in 1992 and 2.44% in 1991.

Amortization
Deferred charges include regulatory assets which are amortized primarily over periods allowed by regulators. Also included in Deferred Charges, Other are debt issuance and redemption costs which are amortized over the terms of the respective debt issues.

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 1993 and 1991, the Company deferred $4.6 million and $1.8 million, respectively, of net power supply cost savings, which resulted in like increases in electric operating expenses. In 1992, the Company deferred $3.3 million of net power supply costs, which resulted in like decreases in electric operating expenses. Rate changes are triggered when the deferred balance reaches $2.2 million. A rate increase was implemented in November 1992 to pass through accumulated costs. A rate reduction was implemented in May 1991 to pass through accumulated cost savings. As of December 31, 1993, $0.6 million of costs not yet subject to a rate increase had accumulated in the PCA deferral account. The PCA is currently scheduled to end on June 30, 1994.

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
Provisions for income taxes are based generally on income and expense as reported for financial statement purposes adjusted principally for the excess of tax depreciation over book depreciation.

Beginning with 1981 property additions, deferred income taxes are provided for the tax effect of Accelerated Cost Recovery System (ACRS) depreciation over straight-line depreciation. Investment tax credits (ITC) are amortized over the period established by regulators.

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 Common Share
Earnings per common 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.

New Accounting Standards

FAS No. 112, entitled "Employers' Accounting for Postemployment Benefits," was issued by the Financial Accounting Standards Board in November 1992 and is effective for fiscal years beginning after December 15, 1993. This Statement requires the accrual of the expected cost of providing benefits to former or inactive employees after employment but before retirement. It has been determined that the liabilities related to the Company's Long-Term Disability and Workers' Compensation programs are affected by this Statement. The Company does not expect FAS No. 112 to have a material effect on the Company's financial position or results of operations.

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 has elected to amortize this obligation of approximately $39,600,000 over a period of twenty years. Income from continuing operations during 1993 was not changed by the implementation of this Statement.

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 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 1993, 1992 and 1991, the Company recognized $1,250,000, $1,290,000 and $1,233,000, 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, 1993.

Accumulated postretirement benefit obligation:

Retirees	509
Fully eligible plan participants	1,341
Other active plan participants	111
Total participants	1,961
Fair value of plan assets	$ 636,000
Accumulated postretirement benefit obligations in excess of plan assets	$38,964,000
Unrecognized transition obligation	$38,413,000
Accrued postretirement benefit cost, deferred	$3,981,000

Net postretirement benefit cost for 1993 consisted of the following components:

Service cost - benefits earned during the period	$776,000
Return on the plan assets (if any)	-
Interest cost on accumulated postretirement benefit obligation	$2,018,000
Amortization of transition obligation	$1,187,000

The currently assumed health care cost trend rate used in measuring the accumulated postretirement benefit obligation is 12.0% for 1993, decreasing linearly each successive year until it reaches 6.0% in 1997. 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, 1993 and net postretirement health care cost by approximately $3,079,000. The assumed discount rate used in determining the accumulated postretirement benefit obligation was 7.5%.

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.

Net pension credit for 1993, 1992 and 1991 is summarized as follows:

	1993	1992	1991
	(Thousands of Dollars)		
Service cost-benefits earned during the period	$ 3,150	$ 2,846	$ 2,614
Interest cost on projected benefit obligation	7,771	7,390	7,064
Actual return on plan assets	(15,108)	(12,257)	(21,933)
Net amortization and deferral	3,717	886	12,586
Net periodic pension cost (income)	(470)	(1,135)	331
Less amounts charged (credited) to construction and other accounts	-	(24)	115
Less regulatory adjustments to operating expenses (1)	-	-	321
Net pension cost credited to operating expenses	$ (470)	$ (1,111)	$ (105)

(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.

The funded status of the Plan and the pension liability at December 31, 1993, 1992 and 1991, are as follows:

	1993	1992	1991
	(Thousands of dollars)		
Actuarial present value of benefit obligations:			
Accumulated benefit obligations (including vested benefits of $(84,531,000), $(76,226,000) and $(71,133,000), respectively)	$ (85,368)	$ (76,853)	$ (71,646)
Projected benefit obligation for service rendered to date	$(104,025)	$ (95,446)	$ (89,780)
Plan assets at fair value	126,879	118,883	116,594
Plan assets in excess of projected benefit obligation	22,854	23,437	26,814
Unrecognized net gain from returns different than assumed	(21,503)	(19,733)	(22,698)
Prior service cost not yet recognized in pension cost	7,983	8,568	8,107
Unrecognized net asset at year-end (being amortized over 11 to 19 years)	(12,445)	(13,531)	(14,617)
Regulatory deferrals	(3,256)	(1,381)	(131)
Pension liability	$ (6,367)	$ (2,640)	$ (2,525)
Assumptions used in calculations were:			
Discount rate at year-end	7.5%	8.5%	8.5%
Rate of increase in future compensation level	4.0%	5.0%	5.0%
Expected long-term rate of return on assets	9.0%	9.0%	9.0%

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 January 1, 1993, the Company accrued net regulatory assets of $171,365,000 related to the probable recovery of FAS No. 109 deferred tax liabilities from customers through future rates. In the third quarter, the balance was adjusted to account for the 35% federal income tax rate, which brought the accrued net regulatory assets balance to $182,196,000. As such, the Company's adoption of FAS No. 109 has no effect on income for 1993. The regulatory assets and deferred tax liabilities are being amortized over the estimated remaining life of the associated assets.

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 tax effects of significant items comprising the Company's net deferred tax liability as of January 1, 1993, restated to reflect the 35% federal income tax rate, are as follows:

Deferred tax liabilities:	
Differences between book and tax basis of property	$105,677,000
Regulatory assets for FAS 109	184,087,000
Regulatory asset for Skagit	2,000,000
Other	14,990,000
Total deferred tax liabilities	$306,754,000
Deferred tax assets:	
Reserves not currently deductible	$ 17,591,000
Gain on sale of office building	1,755,000
Regulatory liability for FAS 109	1,891,000
Other	6,575,000
Total deferred tax assets	$ 27,812,000
Net deferred tax liability	$278,942,000

The provision for income tax expense for 1993 was $42,503,000, of which $35,443,000 and $7,060,000 is current and deferred tax expense, respectively. The provision for income tax expense for 1992 was $41,330,000, of which $24,148,000 and $17,182,000 was current and deferred tax expense, respectively. The provision for income tax expense for 1991 was $38,086,000, of which $31,853,000 and $6,233,000 was current and deferred tax expense, respectively. The current and deferred effective tax rates are approximately the same during all periods.

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, 1993 are as follows:

Year Ended December 31	Maturities	Sinking Fund Requirements	Total
	(Thousands of Dollars)		
1994	$ -	$3,187	$ 3,187
1995	45,000	3,087	48,087
1996	35,000	2,887	37,887
1997	20,000	2,887	22,887
1998	10,000	2,887	12,887

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, 1992 and 1991, $25,000,000, $113,000,000 and $37,000,000, respectively, of unsecured Medium-Term Notes, Series A and B (Notes) were issued. At December 31, 1993, the Company had outstanding $250,000,000 of the Notes with maturities between 1 and 29 years and with interest rates varying between 5.50% and 9.58%.

As of December 31, 1993, the Company had authorization to issue up to $25,000,000 of the $250,000,000 originally authorized in aggregate principal amount of new First Mortgage Bonds issued in the form of Secured Medium-Term Notes, Series A (Secured MTNs). The Secured MTNs may be issued from time to time and may vary in term from 9 months to 30 years. At December 31, 1993, the Company had outstanding $225,000,000 of the Secured MTNs with maturities between 2 and 30 years and with interest rates varying between 4.72% and 7.54%. In January 1994, authorization was received for an additional $250,000,000 of Secured Medium-Term Notes, Series B, which may vary in term from 9 months to 40 years.

At December 31, 1993, the Company had $68,000,749 outstanding under borrowing arrangements which will be refinanced in 1994. 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, 1993 and 1992 is estimated to be $690.0 million, or 107% of the carrying value, and $612.1 million, or 103% 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, 1993, 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, 1995, 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 1/5% 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.

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

	Years Ended December 31,		
	1993	1992	1991
	(Dollars in thousands)		
Balance outstanding at end of period:			
Fixed-term loans	$ 44,001	$ 4,000	$ 13,000
Commercial paper	20,000	-	3,000
Revolving credit agreement	4,000	-	30,000
Maximum balance during period:			
Fixed-term loans	$ 69,000	$ 26,000	$ 20,000
Commercial paper	20,000	24,000	20,805
Revolving credit agreement	28,000	30,000	34,000
Average daily balance during period:			
Fixed-term loans	$ 24,499	$ 9,989	$ 3,797
Commercial paper	7,791	7,351	4,131
Revolving credit agreement	5,030	7,212	4,250
Average annual interest rate during period:			
Fixed-term loans	3.38%	4.26%	5.48%
Commercial paper	3.46	4.18	5.51
Revolving credit agreement	3.49	4.19	5.43
Average annual interest rate at end of period:			
Fixed-term loans	3.55%	4.43%	5.34%
Commercial paper	3.58	-	5.55
Revolving credit agreement	3.65	-	5.28

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, 1993 and 1992, $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 1993, the dividend rate varied from 3.00% to 3.27% and at December 31, 1993, was 3.14%. 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 $30 million in mandatory redemption requirements during the 1994-1998 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, 1993 and 1992 is estimated to be $93.8 million, or 110% of the carrying value, and $89.4 million, or 105% 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 ($12,755,500 at December 31, 1993) 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 1993, the cost recorded for the Plan was $2,216,000. This included the cost for an additional 165,335 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 $1,238,000, $1,776,000 and $1,231,000, respectively.

In February 1990, the Company adopted a shareholder rights plan 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 one-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 $0.01 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 February 16, 2000.

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, 1993, 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 1993, 1992 and 1991, are summarized below (dollar amounts in thousands):

	1993		1992		1991	
	Shares	Amount	Shares	Amount	Shares	Amount
Balance at January 1..................	50,888,130	$508,202	47,901,602	$458,371	46,423,826	$434,936
Employee Investment Plan (401-K)	165,335	3,216	186,724	3,147	150,460	2,317
Dividend Reinvestment Plan.....	1,127,680	21,779	1,341,004	22,721	934,916	14,551
Periodic Offering....................	576,400	11,412	1,458,800	23,963	392,400	6,567
Total Issues...........................	1,869,415	36,407	2,986,528	49,831	1,477,776	23,435
Balance at December 31.............	52,757,545	$544,609	50,888,130	$508,202	47,901,602	$458,371

NOTE 9. FEDERAL INCOME TAXES

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

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. A tax adjustment of $1.6 million related to the sale was recorded in 1991. 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 settlement with BPA and other parties does not affect the Company's obligations under the Ownership Agreement among the owners of Project 3. In connection with its 1993 rate proceedings, BPA has proposed termination of Project 1 and 3. Termination of Project 3 will require proposal of a termination budget and approval by BPA and the Project 3 Owners under the Ownership Agreement. The Company would be reimbursed for the cost of termination under the settlement with BPA.

The only material claim against the Company arising out of the Company's involvement in Project 3, which is still pending 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 is seeking a reallocation of $495 million in costs (plus interest since commencement of construction in 1976) originally allocated to Projects 4 and 5.

On October 7, 1992, the District Court issued an order ruling in favor of the defendants, including the Company, that the "proportional" allocation methodology actually employed by the Supply System was permitted by the Projects 4 and 5 bond resolution. This ruling does not resolve all cost reallocation claims pending in the District Court, including whether the Supply System correctly followed its methodology. Chemical Bank has indicated its intent to assert claims for cost reallocations based upon other theories which have not been litigated. The case is now in the discovery phase on those claims, as settlement talks were not successful.

The Company cannot predict whether Chemical Bank will ultimately be successful in its claim for reallocation of any of the costs of Supply System projects, nor can the Company predict any amounts which might be reallocated to Project 3 or to the Company due to its 5% ownership interest therein. The Company also has claims pending against the Supply System and Chemical Bank with respect to a subordinated loan made by the Company to Projects 4 and 5 in 1981, in the amount of approximately $11 million including interest. The District Court has deferred ruling on the Company's motion to set-off the amount due on the loan, including interest, against any recovery by Chemical Bank on its cost reallocation claims. The Company intends to continue to defend this suit vigorously. Since the discovery is not yet complete, the Company is 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.

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 in this case has been stayed pending a decision by the Court on a case involving some similar issues between Idaho Power Company and the Nez Perce Tribe. The case is not yet set for trial. The Company intends to vigorously defend against the Tribe's claims. Since the discovery is not yet complete, the Company is 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. 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 is claiming the Company's dam interfered with Indian fishing rights. The Tribe is also seeking a declaratory judgment and quiet title to part of the property comprising the Little Falls Hydroelectric Development. Discovery conducted by the Company revealed that the Tribe may seek damages in the range of $100 million to $1.4 billion, to compensate them for the alleged loss of fishing rights, alleged lost opportunity to develop the properties, and alleged damage to the Tribe's cultural heritage. The trial of these matters is currently scheduled for April 1994 in the United States District Court for the Eastern District of Washington, in Spokane, Washington. On the merits, the Company claims that it has all of the right, title and interest necessary for the construction, operation and maintenance of the Little Falls Development, which rights, title and interest were duly acquired from the United States pursuant to a 1905 Act of Congress. The Company intends to vigorously defend against the Tribe's claims. The Company is 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.

Steam Heat Plant

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 leak. 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 beyond the steam plant property. On December 6, 1993, the Company asked the DOE to approve a voluntary proposal to begin extracting the underground oil. The extraction process is intended to remove quantities of the oil and relieve any pressure on the deposit which might cause it to move. In December 1993, the Company established a reserve of $2.0 million, which is the current best estimate of mitigation costs.

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. On October 13, 1993, three separate class action lawsuits were filed by private individuals in the Superior Court of Spokane County in connection with fires occurring in the Midway, Nine Mile and Chattaroy regions of eastern Washington. Service of these suits, together with a fourth suit, occurred on January 7, 1994. Complainants allege various theories of tortious conduct, including negligence, creation of a public nuisance, strict liability and trespass. 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. The Superior Court has yet to certify these lawsuits as class actions. The Company intends to vigorously defend against all such pending claims. Since the discovery is not yet complete, the Company is 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.

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, 1993:

Project	KW of Installed Capacity	Fuel Source	Company's Current Share of: Ownership (%)	Plant in Service	Accumulated Depreciation	Net Plant In Service	Construction Work in Progress
				(Thousands of Dollars)			
In service:							
Centralia	1,313,000	Coal	15%	$ 54,424	$ 29,285	$ 25,139	$ 273
Colstrip 3 & 4	1,400,000	Coal	15	263,882	72,184	191,698	-

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, 1993, 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	$ 2,685	$ 311	$ 3,710	1995
Rocky Reach Project	2.9	37,000	1,016	584	5,503	2011
Grant County PUD:						
Priest Rapids Project	6.1	55,000	1,658	1,119	8,616	2005
Wanapum Project	8.2	75,000	2,392	1,724	15,530	2009
Douglas County PUD:						
Wells Project	3.9	30,000	970	595	7,797	2018
Totals		255,000	$ 8,721	$ 4,333	$ 41,156	

(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 1993.
(3) Included in annual costs.

Actual expenses for payments made under the above contracts for the years 1993, 1992 and 1991, were $8,721,000, $8,433,000 and $7,589,000, 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 $4,338,000 in 1994, $4,775,000 in 1995, $3,830,000 in 1996, $4,300,000 in 1997 and $4,684,000 in 1998 (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 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. At December 31, 1993, Pentzer had approximately $130 million in assets compared to $103 million at the end of 1992.

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 is accounted for by the equity method and is included in Other Income-Net and its investment in ITRON is reflected on the balance sheet under Other Property and Investments. As a result of ITRON's initial public offering in November 1993 and Pentzer's sale of a portion of its ITRON stock, Pentzer's ownership interest in ITRON was reduced to approximately 25%.

In December 1992, the Company completed the purchase of the northern Idaho electric distribution assets of Citizens Utilities. The cash purchase price of $1.2 million included a premium above the book value of the net assets acquired. The premium will be amortized over a 19-month period. The purchase provided approximately 2,100 additional electric customers. The Company believes that this acquisition will not have a material impact on its revenues or its operations.

On September 30, 1991, the Company completed the purchase of the Oregon and South Lake Tahoe, California, natural gas assets of CP National Corporation, a subsidiary of ALLTEL Corporation, for approximately $67.9 million. The cash purchase included a premium of approximately $24.9 million above the book value of the net assets acquired. The premium and other costs associated with acquiring the properties will be amortized under a straight-line method over 20 years and the amortization may be accelerated depending upon earnings. The California and Oregon Commissions have agreed to a general rate "freeze" which extends to January 1, 1996, in California and to December 31, 1995, in Oregon. Purchased natural gas costs will continue to be tracked through to customers during the rate "freeze" period.

On February 15, 1994, the Company announced it had reached agreement to acquire the northern Idaho electric properties of Pacific Power & Light Company, an operating division of PacifiCorp. The cash purchase price will be $26 million, subject to adjustments upon closing. The approximate book value of the assets is $19 million. The purchase agreement is subject to approval by the IPUC and FERC. It is anticipated the acquisition will be completed mid-year 1994. Pacific Power's northern Idaho electric system currently serves approximately 9,300 customers. The Company believes this acquisition will not have a material impact on its revenues or its operations.

Sch. 19	MONTANA PLANT IN SERVICE (ASSIGNED AND ALLOCATED)		
Account Number and Title	Last Year	This Year	% Change
Intangible Plant			
301 Organization			
302 Franchies and Consents	193,078	193,078	0.00
303 Miscellaneous Intangible Plant	34,006	52,147	53.35
TOTAL Intangible Plant	227,084	245,225	7.99
Production Plant			
Steam Production			
310 Land & Land Rights	1,304,594	1,304,594	0.00
311 Structures & Improvements	98,905,194	99,019,372	0.12
312 Boiler Plant Equipment	113,994,988	114,046,452	0.05
313 Engines & Engine Driven Generators			
314 Turbo Generator Units	23,412,215	24,164,354	3.21
315 Accessory Power Plant Equipment	13,387,393	13,405,701	0.14
316 Miscellaneous Power Plant Equipment	11,836,724	11,941,356	0.88
TOTAL Steam Production Plant	262,841,108	263,881,829	0.40
Nuclear Production			
320 Land & Land Rights			
321 Structures & Improvements			
322 Reactor Plant Equipment			
323 Turbogenerator Units			
324 Accessory Electric Equipment			
325 Miscellaneous Power Plant Equipment			
TOTAL Nuclear Production Plant	0	0	0.00
Hydraulic Production			
330 Land and Land Rights	37,917,514	37,917,514	0.00
331 Structures and Improvements	9,961,609	10,146,451	1.86
332 Resevoirs, Dams and Waterways	30,756,391	30,756,777	0.00
333 Water Wheels, Turbines and Generators	28,735,191	30,436,161	5.92
334 Accessory Electric Eqipment	2,464,885	2,494,420	1.20
335 Miscellaneous Power Plant Equipment	1,363,299	1,496,389	9.76
336 Road, Railroads & Bridges	88,694	88,694	0.00
TOTAL Hydraulic Production Plant	111,287,583	113,336,406	1.84

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	374,128,691	377,218,235	0.83
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	14,184,882	14,227,946	0.30
354 Towers & Fistures	15,986,603	15,986,603	0.00
355 Poles & Fixtures	6,715,953	6,714,559	(0.02)
356 Overhead Conductors and Devices	15,688,188	15,696,272	0.05
357 Underground Conduit			
358 Underground Conductors & Devices			
359 Roads & Trails	367,477	367,477	0.00
TOTAL Transmission Plant	53,957,014	54,006,768	0.09
Distribution Plant			
360 Land & Land Rights	15,881	15,881	0.00
361 Structures & Improvements	132,818	133,565	0.56
362 Station Equipment			
363 Storage Battery Equipment	8,955	8,955	0.00
364 Poles, Towers and Fixtures	6,676	6,934	3.86
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	166,067	167,072	0.61

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	3,717	15,694	0.00
7	392 Transportation Equipment	80,259	102,366	27.54
8	393 Stores Equipment			
9	394 Tools, Shop and Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment	220,920	220,920	0.00
12	397 Communications Equipment	2,378,160	2,381,641	0.15
13	398 Miscellaneous Equipment	290	290	0.00
14	399 Other Tangible Property			
15				
16	TOTAL General Equipment	2,683,346	2,720,911	1.40
17				
18	TOTAL Electric Plant in Equipment	431,162,202	434,358,211	0.74

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)	262,577,235	64,282,865	72,240,075	26.00
3	Nuclear Production				
4	Hydro Production (Noxon Plant)	103,514,266	6,514,949	7,029,738	6.54
5	Other Production				
6	Transmission Not Available				
7	Distribution Not Available				
8	General Not Available				
9	**TOTAL**	366,091,501	70,797,814	79,269,813	20.50

Sch 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)			
	Account	Last Year Bal.	This Year Bal.	% Change
1				
2	151 Fuel Stock	526,299	604,999	14.95
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)	2,209,291	2,375,807	7.54
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	2,735,590	2,980,806	8.96

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 Stocck	Reference is made to Schedule 28		
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	82,776,035	74,669,878	10.86
6	Depreciation	42,263,357	41,494,082	1.85
7	Amortization	21,448,862	14,804,367	44.88
8	Deferred Income Taxes - Net	9,704,256	14,880,420	(34.79)
9	Investment Tax Credits - Net	(97,847)	(701,532)	(86.05)
10	Change in Operating Receivables - Net	(1,407,340)	(4,947,378)	(71.55)
11	Change in Materials, Supplies & Inventories - Net	(2,001,065)	1,046,913	(291.14)
12	Change in Operating Payable & Accrued Liabilities - Net	5,828,574	(1,352,441)	(530.97)
13	Allowance for Funds Used During Construction (AFUDC)	(1,666,118)	(1,391,562)	19.73
14	Change in Assets and Liabilities - Net			
15	Other Operating Activities (explained on attached page)	(15,217,230)	(19,900,132)	(23.53)
16	Net Cash Provided by/(Used in) Operating Activities	141,631,484	118,602,615	19.42
17				
18	**Cash Inflows/Outflows From Investment Activities**			
19	Construction/Acquisition of Property, Plant and Related Equipment	(107,677,013)	(76,158,946)	(41.38)
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)	(33,820,465)	(16,816,510)	(101.11)
27	Net Cash Provided by/(used in) Investing Activities	(141,497,478)	(92,975,456)	(52.19)
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	250,000,000	113,000,000	(121.24)
32	Preferred Stock	0	35,000,000	100.00
33	Common Stock	36,405,617	49,831,987	26.94
34	Other: Accounts Receivable Sale	0	10,000,000	100.00
35	Net Increase (Decrease) in Short-Term Debt	64,000,749	(42,000,000)	252.38
36	Other: Notes Receivable-ESOP	432,750	380,750	(13.66)
37	Payment for Retirement of:			
38	Long-Term Debt	(270,000,000)	(105,000,000)	(157.14)
39	Preferred Stock	0	(25,000,000)	100.00
40	Common Stock			
41	Other:			
42	Net Decrease in Short-Term Debt	(12,325,475)	(42,064)	(29,201.72)
43	Dividends on Preferred Stock	(8,503,780)	(6,683,481)	(27.24)
44	Dividends on Common Stock	(64,208,970)	(61,525,126)	(4.36)
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	(4,199,109)	(32,037,934)	(86.89)
47				
48				
49	**Net Increase/Decreses in Cach and Cash Equivalents**	(4,065,103)	(6,410,775)	(36.59)
50	**Cash and Cash Equivalents at Beginning of Year**	163,775	6,574,530	(97.51)
51	**Cash and Cash Equivalents at End of Year**	(3,901,328)	163,755	(2,482.42)

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	(13,393,041)	(10,695,362)	(25.22)
6	Idaho Accretion Income	(388,721)	(426,750)	8.91
7	Change in Dividend Declared	284,750	(284,750)	200.00
8	Non-Monetary Power Transactions	(321,207)	(418,978)	23.34
9	Regulatory gas cost and power cost adjustment	(7,624,455)	(11,523,200)	33.83
10	Other Changes-Net	6,225,444	3,448,908	(80.50)
11	Total Line 15	(15,217,230)	(19,900,132)	23.53
12				
13				
14	**Line 26: Other Investing Activities**			
15	Additions in Non-Utility Plant	(302,077)	(12,959,003)	97.67
16	Other Capital Requirements	(30,215,429)	(10,944,454)	(176.08)
17	Dividends Received from Subsidiary Companies	0	3,600,000	
18	Changes in Noncurrent Balance Sheet Accounts	(1,147,620)	5,836,461	119.66
19	Other Special Funds	(2,155,339)	(2,349,514)	8.26
	Total Line 26	(33,820,465)	(16,816,510)	(101.11)

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%	255,348	6.53%
8									
9	Secured Medium Term Notes	Var.	Var.	225,000,000	223,530,875	225,000,000	7.42%	16,507,968	7.39%
10									
11									
12									
13									
14									
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31									
32									
33	TOTAL Year End			322,800,000	317,387,549	322,800,000			

Sch.25 **PREFERRED STOCK**

Line	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%
33	TOTAL					126,880,656		135,000,000		

Sch.26

COMMON STOCK

Month	Avg. Number of Shares Outstanding(1)	Book Value Per Share(1)	Earnings Per Share(1)	Dividends Per Share(1)	Retention Ratio(1)	Market Price(1) High	Market Price(1) Low	Price/ Earnings Ratio(1)
January	50,936,621	11.90				18.4375	17.3750	12.01
February	51,063,947	11.76				19.1875	18.3125	12.03
March	51,210,522	11.98	.66	.31		19.3750	18.9375	12.46
April	51,345,790	12.08				19.6875	19.0000	12.50
May	51,475,388	11.86				20.0000	18.8750	12.87
June	51,655,010	12.01	.27	.31		19.8375	19.2500	13.08
July	51,843,689	11.72				20.2500	19.7500	13.50
August	51,983,661	11.77				21.0000	20.0625	14.21
September	52,168,618	11.89	.10	.31		20.7500	20.0000	13.93
October	52,338,358	12.05				20.4375	19.1250	13.04
November	52,443,020	11.95				19.6875	18.1250	11.27
December	52,595,067	12.06	.41	.31		19.1250	18.1250	13.02
TOTAL Year End			1.44	1.24	13.9%			

(1) Adjusted to reflect the 2-for-1 stock split effective November 9, 1993.

Sch.27

OTHER CAPITAL

Description	Outstanding Per Balance Sheet	Range Cost %	Weighted Cost %
Unsecured Medium Term Notes-Series A	100,000,000	7.94 to 9.58	9.18
Unsecured Medium Term Notes-Series B	150,000,000	5.50 to 8.55	7.38
Commercial Paper	20,000,000		3.58
Fixed Term Loans	44,000,749		3.57
$70 Million Credit Line	4,000,000		3.65
Capital Leases	636,536		10.00*
Other	329,733		8.00*
*Estimated			
TOTAL	318,967,018		

Sch. 28	MONTANA EARNED RATE OF RETURN			
	Description Rate Base	Last year	This Year	% Change
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 16 customers with 1993 revenues amounting to $3,144,590 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.			
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49				
50	**Adjusted Rate of Return on Average Rate Base**			
51				
52	**Adjusted Rate of Return on Average Equity**			

Sch. 29	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	2,980,806
9		(Less):	
10	108,111	Depreciation & Amortization Reserves	79,269,813
11	252	Contributions in Aid of Construction	
12			
13		NET BOOK COSTS	359,690,939
14			
15			
16		Revenues & Expenses	
17			
18	400	Operating Revenues	3,144,590
19			
20	403 - 407	Depreciation & Amortization Expenses	8,558,453
21	409	Federal Income Taxes (State Only, Federal Not Allocated)	667,886
22	408	Other Taxes	9,108,557
23		Other Operating Expenses	35,578,294
24		TOTAL Operating Expenses	
25			
26		Net Operating Income	(50,768,600)
27			
28	415 - 421.1	Other Income	-
29	421.2 - 426.5	Other Deductions	-
30			
31		NET INCOME(LOSS)	(50,768,600)
32			
33			
34		Customers (Intrastate Only)	
35			
36		Year End Average:	
37		Residential	12
38		Commercial	3
39		Industrial	
40		Other	1
41			
42		TOTAL NUMBER OF CUSTOMERS	16
43			
44			
45		Other Statistics (Intrastate Only)	
46			
47		Average Annual Residential Use (Kwh)	18,173
48		Average Annual Residential Cost per (kwh) (Cents) *	4.70
49		* Avg annual cost = {(cost per Kwh x annual use) + (mo. svc chrg x 12)}/annual use	
50		Average Residential Monthly Bill	71.13
51		Gross Plant per Customer	36,196,518

Sch.30 MONTANA CUSTOMER INFORMATION

	City / Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1						
2	Noxon, Montana		12	3		15
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		12	3	1	16

Sch. 31	MONTANA EMPLOYEE COUNTS			
	Department	Year Beginning	Year End	Average
1				
2	Noxon Generating Station	15	14	14.5
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52				
53	TOTAL Montana Employees	15	14	14.5

Sch. 32	MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1	1994 Construction Budget		
2			
3	Colstrip, Montana		
4	Colstrip Generating Station--Various Additions		1,977,200
5			
6	Noxon, Montana		
7	Noxon Rapids Generating Station, Noxon - Replace Stator Cooling Control		50,000
8	Noxon Rapids Generating Station - Install Emergency Generator		10,000
9	Noxon Rapids Generating Station and Reservoir - Relicensing Costs		1,376,000
10	Noxon 230 KV Switchyard - Replace Relay on the Noxon-Hot Springs 230 KV Line		75,000
11	Total		1,511,000
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53	TOTAL		3,488,200

Sch. 33	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.	13	800	1521	1,220,817	375,722
2	Feb.	17	800	1474	1,071,959	353,018
3	Mar.	1	800	1376	954,932	249,810
4	Apr.	13	800	1163	765,736	137,038
5	May	7	800	1040	811,971	227,854
6	Jun.	18	1300	1013	852,817	283,240
7	Jul.	28	1600	1028	871,541	303,117
8	Aug.	5	1600	1072	826,836	221,037
9	Sep.	22	800	1053	804,316	224,024
10	Oct.	20	800	1096	834,743	231,331
11	Nov.	24	800	1425	972,302	231,646
12	Dec.	6	800	1291	1,041,462	265,561
13	TOTAL				11,029,432	3,103,398
		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	35	0
15	Feb.	"		"	7,266	6,825
16	Mar.	"	"	"	3,568	3,345
17	Apr.	"	"	"	10,937	10,305
18	May	"	"	"	35,023	33,044
19	Jun.	"	"	"	42,890	40,480
20	Jul.	"	"	"	10,629	10,020
21	Aug.	"	"	"	724	670
22	Sep.	"	"	"	13	0
23	Oct.	"	"	"	76	50
24	Nov.	"	"	"	108	80
25	Dec.	"	"	"	59	30
26	TOTAL				111,328	104,849

Sch. 34	TOTAL SYSTEM Sources & Disposition of Energy			
	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (net of Station Use)			
2	Steam	2,765,749	Sales to Ultimate Consumers	7,187,386
3	Nuclear		(Less Interdepartmental)	
4	Hydro - Conventional	3,547,591		
5	Hydro - Pumped Storage		Requirements: Sales	
6	Other	25,637	for Resale	154,812
7	(Less) Energy for Pumping			
8	**NET Generation**	6,338,977	Non - Requirements: Sales	
9	Purchases	4,609,769	for Resale	3,103,398
10	Power Exchanges			
11	Received	1,220,219	Energy Furnished	
12	Delivered	(1,139,533)	Without Charge	0
13	**NET Exchanges**	80,686		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	3,569,890	Electric Utility	0
16	Delivered	3,569,890		
17	**Net Transmission Wheeling**	0	Total Energy Losses	583,836
18	Transmission Lossed by Others			
19	**TOTAL**	11,029,432	**TOTAL**	11,029,432

Sch. 35	SOURCES OF ELECTRIC ENERGY				
	Type	Plant Name	Location	Annual Peak	Annual Energy
1	Washington				
2	Thermal	Centralia	Centralia, WA	210.0	1,256,845
3	Thermal	Kettle Falls	Kettle, Falls, WA	50.0	307,968
4	Hydro	Little Falls	Ford, WA	36.0	176,482
5	Hydro	Long Lake	Ford, WA	72.8	398,905
6	Hydro	Meyers Falls	Colville, WA	1.3	7,144
7	Hydro	Monroe Street	Spokane, WA	13.0	81,430
	Hydro	Nine Mile	Spokane, WA	18.0	95,857
8	Hydro	Upper Falls	Spokane, WA	10.2	80,206
9	Combustion Turbine	Northeast	Spokane, WA	65.0	25,637
10					
11	Total Washington				2,430,474
12					
13					
14	Idaho				
15	Hydro	Cabinet Gorge	Clark Fork, ID	212.5	1,017,886
16	Hydro	Post Falls	Post Falls, ID	18.0	76,285
17					1,094,171
18	Total Idaho				
19					
20					
21	Montana				
22	Thermal	Colstrip #3 & #4	Colstrip, MT	216.0	1,200,936
23	Hydro	Noxon	Thompson Falls, MT	466.2	1,613,396
24					2,814,332
25	Total Montana				
26					
27					
28					
29					
30					
31	Total System				6,338,977
32					
33					
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51					
52	TOTAL				

Sch.36 **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							
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