PF

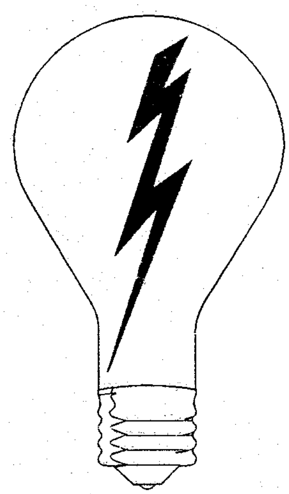
YEAR 1992

ANNUAL REPORT
OF

The Washington Water Power Company

(COMPANY NAME)

ELECTRIC UTILITY



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AUG 02 1993
MONT. P. S. COMMISSION

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

REVISED OCTOBER 20, 1992

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Sch. 1 IDENTIFICATION

Legal Name of Respondent:	The Washington Water Power Company
Name Under Which Respondent Does Business:	The Washington Water Power Company
Date Utility Service First Offered in Montana:	July, 1960
Person Responsible for Report:	J. E. Eliassen, Vice President-Finance & CFO
Telephone Number for Report Inquiries:	(509) 482-4335
Address for Correspondence Concerning Report:	E. 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*	E. 1411 Mission Ave, Spokane, WA 99202	492,798
2	J. R. Harvey*	E. 1411 Mission Ave, Spokane, WA 99202	278,569
3	David A. Clack	E. 325 Sprague Ave, Spokane, WA 99202	19,305
4	Duane B. Hagadone	P.O. Box 6200, Coeur d'Alene, ID 83816	21,167
5	Eugene W. Meyer	3 Plumbridge Lane, Hilton Head Island, SC	
6		29928	34,586
7	B. Jean Silver	N. 7102 Audubon Dr, Spokane, WA 99208	14,940
8	Larry A. Stanley	E. 1501 Trent Ave, Spokane, WA 99202	19,343
9	R. John Taylor	P.O. Box 538, Lewiston, ID 83501	22,969
10	Eugene Thompson	3307 Pinecrest Rd, Moscow, ID 83843	3,924

*Mr. Redmond and Mr. Harvey are Chairman of the Board and Chief Executive Officer; and President and Chief Operating Officer, respectively. Amounts shown reflect annual remuneration.

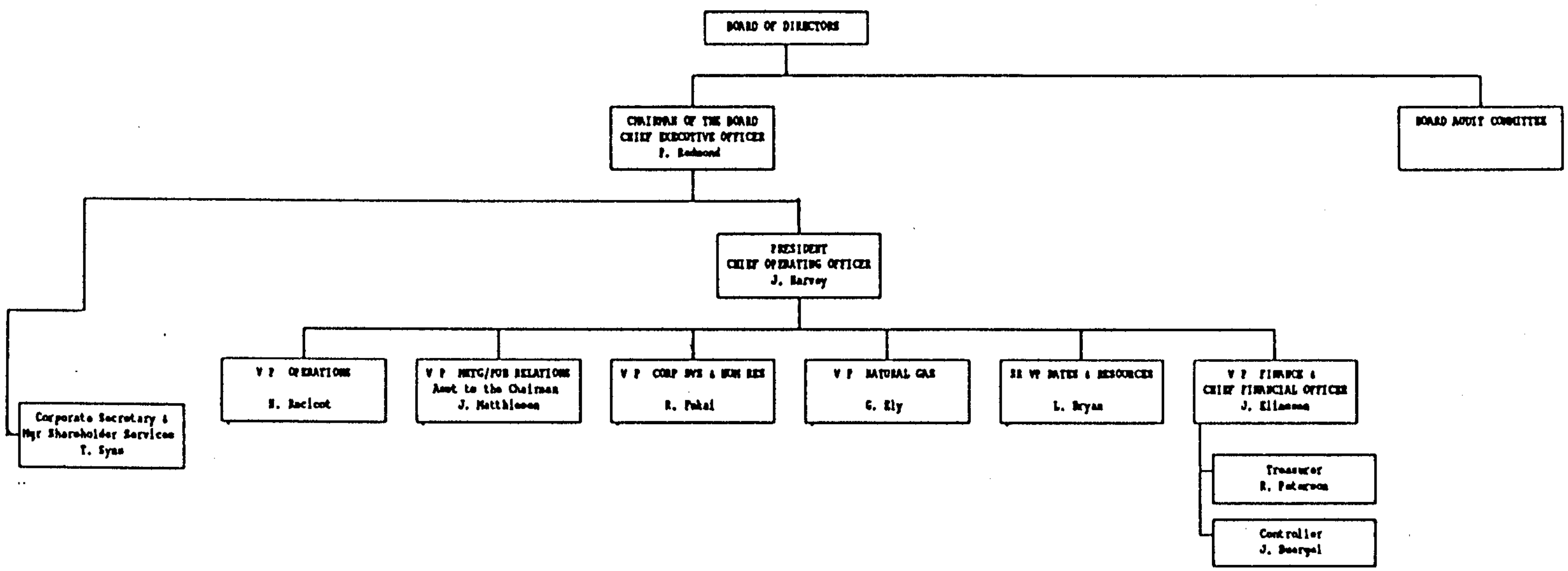
Sch. 3

OFFICERS

Title	Department Supervised	Name
Chairman of the Board & Chief Exec Officer	*	P. A. Redmond
President & Chief Operating Officer	*	J. R. Harvey
Vice President-Finance & Chief Fin. Officer	Finance Department	J. E. Eliassen
Sr. Vice President	Rates & Resources	W. L. Bryan
Vice President	Marketing, Public Relations	J. G. Matthiesen
Vice President	Corporate Services, Human Resources	R. D. Fukai
Vice President	Natural Gas	G. G. Ely
Vice President	Operations	N. J. Racicot
Treasurer	Funds Management, Tax & Payroll, Corporate Finance & Investor Relations	R. R. Peterson
Controller	Corp. Acctg, Plant Acctg. & Rates	J. W. Buergel
Corporate Secretary	Shareholder Services	T. L. Syms

*See organization chart attached

WASHINGTON WATER POWER
ORGANIZATIONAL CHART
AS OF OCTOBER 1992



Sch. 4

CORPORATE STRUCTURE

Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
Pentzer Corporation	Parent Company of all of the Company's Subsidiaries, except Washinton Irrigation and Development Co. and WP Finance	$8,360,788	78.17
Washington Irrigation & Development Co	Non-Operating, Sold mining asset in July, 1990	$2,334,574	21.83
WP Finance	Makes consumer loans on energy-related products, and owns thorium deposits in Idaho	0	0
TOTAL		$10,695,362	

CORPOR E ALLOCATIONS

Sch	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Not Applicable					
2						
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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)	Affiliate Trans. (Y or N)	Mortgage Release (Y or N)	Trans. Amount (000)	Gain Loss (000)
1	Not Applicable									
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S. 7	AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY					
	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% Total Affil. Revs.	Charges to MT Utility
1	Not Applicable					
2						
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Sc 8 AFFILIATE TRANSACTIONS ODUCTS & SERVICES PROVIDED BY UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% Total Affil. exp.	Revenues to MT Utility
1	Not Applicable					
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Sch. 9 MONTANA UTILITY INCOME STATEMENT

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	3,826,152	2,062,617	(46.09)
2				
3	Operating Expenses			
4	401 Operation Expenses	27,148,099	28,551,678	5.17
5	402 Maintenance Expenses	4,853,110	5,205,554	7.26
6	403 Depreciation Expenses	8,435,008	8,545,149	1.3
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	None or	not allocated	
11	408.1 Taxes Other Than Income Taxes	8,715,027	8,145,463	(6.54)
12	409.1 Income Taxes - Federal	None or	not allocated	
13	- Other	757,392	853,580	12.70
14	410.1 Provision for Deferred Income Taxes	None or	not allocated	
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	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	49,908,636	51,301,424	2.79
21				
22	NET UTILITY OPERATING INCOME	(46,082,484)	(49,238,807)	(6.84)

Sch. 10 MONTANA REVENUES

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Electricity			
2	440 Residential	12,097	10,487	(13.31)
3	442 Commercial & Industrial - Small	13,747	11,455	(16.67)
4	Commercial & Industrial - Large			
5	444 Public Street & Highway Lighting			
6	445 Other Sales to Public Authorities			
7	446 Sales to Railroads & Railways			
8	448 Interdepartmental Sales			
9				
10	TOTAL Sales to Ultimate Consumers	25,844	21,942	(15.10)
11	447 Sales for Resale	2,554,360	887,581	(65.25)
12				
13	TOTAL Sales of Electricity	2,580,204	909,523	(64.75)
14	449.1 (Less) Provision for Rate Refunds			
15				
16	TOTAL Revenue Net of Provision for Refunds			
17	Other Operating Revenues			
18	450 Forfeited Discounts & Late Payment Revenues			
19	451 Miscellaneous Service Revenues			
20	453 Sales of Water & Water Power	6,327	13,284	109.96
21	454 Rent From Electric Property	121,068	99,676	(17.67)
22	455 Interdepartmental Rents			
23	456 Other Electric Revenues	1,118,553	1,040,134	(7.01)
24				
25	TOTAL Other Operating Revenues	1,245,948	1,153,094	(7.45)
26				
27	Total Electric Operating Revenues	3,826,152	2,062,617	(46.09)

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	327,894	331,107	0.98
8	(501) Fuel	11,839,999	13,459,161	13.68
9	(502) Steam Expenses	1,151,458	1,304,319	13.28
10	(503) Steam from Other Sources			
11	(Less) Steam Transferred-Cr.			
12	(505) Electric Expenses	488,231	460,482	(5.68)
13	(506) Miscellaneous Steam Power Expenses	926,321	1,285,305	38.75
14	(507) Rents	8,071	2,762	(65.78)
15				
16	TOTAL Operation - Steam	14,741,974	16,843,136	14.25
17				
18	Maintenance			
19	(510) Maintenance Supervision and Engineering	379,683	403,696	6.32
20	(511) Maintenance of Structures	299,556	375,032	25.20
21	(512) Maintenance of Boiler Plant	2,215,722	2,156,274	(2.68)
22	(513) Maintenance of Electric Plant	713,311	1,010,431	41.65
23	(514) Maintenance of Miscellaneous Steam Plant	284,500	424,658	49.26
24				
25	TOTAL Maintenance - Steam	3,892,772	4,370,091	12.26
26				
27	TOTAL Power Production Expenses-Steam Plant	18,634,746	21,213,227	13.84
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	78,419	85,993	9.66
6	(536) Water for Power			
7	(537) Hydraulic Expenses	27,840	33,128	18.99
8	(538) Electric Expenses	499,678	519,157	3.90
9	(539) Miscellaneous Hydraulic Power Generation Expenses	90,417	91,525	1.23
10	(540) Rents	45	0	
11				
12	TOTAL Operation - Hydraulic	696,399	729,803	4.80
13				
14	Maintenance			
15	(541) Maintenance Supervision and Engineering	16,895	3,909	(76.86)
16	(542) Maintenance of Structures	100,993	50,985	(49.52)
17	(543) Maintenance of Reservoirs, Dams, and Waterways	105,995	26,585	(74.92)
18	(544) Maintenance of Electric Plant	489,108	613,309	25.39
19	(545) Maintenance of Miscellaneous Hydraulic Plant	11,575	28,497	146.19
20				
21	TOTAL Maintenance - Hydraulic	724,566	723,285	(0.18)
22				
23	TOTAL Hydraulic Power Production Expenses	1,420,965	1,453,088	2.26
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	15	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	15	0	
43				
44	TOTAL Power Production Expenses-Other Power	15	0	
45				
46	**Other Power Supply Expenses**			
47	(555) Purchased Power	10,684,782	9,901,658	(7.33)
48	(556) System Control and Load Dispatching			
49	(557) Other Expenses			
50				
51	TOTAL Other Power Supply Expenses	10,684,782	9,901,658	(7.33)
52				
53	TOTAL Power Production Expenses	30,740,508	32,567,973	5.94

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	20,885	22,857	9.44
4	(561) Load Dispatching	10,415	13,118	25.95
5	(562) Station Expenses	63,582	63,828	0.39
6	(563) Overhead Line Expenses	5,950	8,108	36.27
7	(564) Underground Line Expenses			
8	(565) Transmission of Electricity by Others	233,281	94,611	(59.44)
9	(566) Miscellaneous Transmission Expenses			
10	(567) Rents	72,762	77,462	6.46
11				
12	TOTAL Operation - Transmission	406,875	279,984	(31.19)
13	Maintenance			
14	(568) Maintenance Supervision and Engineering	6,349	7,456	17.44
15	(569) Maintenance of Structures	6	11	83.33
16	(570) Maintenance of Station Equipment	125,785	41,163	(67.28)
17	(571) Maintenance of Overhead Lines	58,268	22,583	(61.24)
18	(572) Maintenance of Underground Lines			
19	(573) Maintenance of Miscellaneous Transmission Plant			
20				
21	TOTAL Maintenance - Transmission	190,408	71,213	(62.60)
22				
23	TOTAL Transmission Expenses	597,283	351,197	(41.20)
24				
25	**DISTRIBUTION EXPENSES**			
26	Operation			
27	(580) Operation Supervision and Engineering			
28	(581) Load Dispatching			
29	(582) Station Expenses	320	6	(98.13)
30	(583) Overhead Line Expenses			
31	(584) Underground Line Expenses			
32	(585) Street Lighting and Signal System Expenses			
33	(586) Meter Expenses			
34	(587) Customer Installations Expenses			
35	(588) Miscellaneous Distribution Expenses			
36	(589) Rents			
37				
38	TOTAL Operation - Distribution	320	6	(98.13)
39	Maintenance			
40	(590) Maintenance Supervision and Engineering			
41	(591) Maintenance of Structures		60	
42	(592) Maintenance of Station Equipment	2,983		
43	(593) Maintenance of Overhead Lines		48	
44	(594) Maintenance of Underground Lines	111		
45	(595) Maintenance of Line Transformers			
46	(596) Maintenance of Street Lighting and Signal Systems	49		
47	(597) Maintenance of Meters	68	66	(2.94)
48	(598) Maintenance of Miscellaneous Distribution Plant			
49				
50	TOTAL Maintenance - Distribution	3,211	174	(94.58)
51				
52	TOTAL Distribution Expenses	3,531	180	(94.90)
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			
34	(Less) (922) Administrative expenses Transferred-Credit			
35	(923) Outside Services Employed			
36	(924) Property Insurance	75,363	69,369	(7.95)
37	(925) Injuries and Damages	33,982	29,472	(13.27)
38	(926) Employee Pensions and Benefits	2,033	1,900	(6.54)
39	(927) Franchise Requirements			
40	(928) Regulatory Commission Expenses	506,313	696,350	37.53
41	(Less) (929) Duplicate Charges-Cr.			
42	(930.1) General Advertising Expenses	58		
43	(930.2) Miscellaneous General Expenses			
44	(931) Rents			
45				
46	TOTAL Operation	617,749	797,091	29.03
47	Maintenance			
48	(935) Maintenance of General Plant	42,138	40,791	(3.20)
49				
50	TOTAL Administrative and General Expenses	659,887	837,882	26.97
51				
52	TOTAL Electric Operation and Maintenance Expenses	32,001,209	33,757,232	5.49
53				

Sch. 12 MONTANA TAXES OTHER THAN INCOME

Description of Tax	Last Year	This Year	% Change
Reals' Personal Property Tax	7,977,528	8,105,871	1.60
Beneficial Use Tax		(574,709)	
Kilowatt Hour Tax	729,639	609,103	(16.52)
Unemployment Tax	4,070	4,492	10.37
Consumer Council Tax	3,795	659	(82.64)
Public Commission Tax	85	47	(44.71)
TOTAL MT Taxes other than Income	8,715,117	8,145,463	(6.54)

Sch. 13 PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1					
2	Reference is made to Pages 357 through 357-I of the 1992 Form 2 attached.				
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53	TOTAL Payments for Services				

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

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

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

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

(c) basis of charges,

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

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

3. Designate with an asterisk associated companies.

(a) Acres International Corporation	
10201 Southport Road SW	
5th Floor	
Calgary, AB CANADA T2W4X9	
(b) Consulting Engineers	
(c) Deferred	$46,954
Capital	$55,314
Operating	$1,779
Total	$104,047
(a) Baumgarten	
444 West 23rd Avenue	
Spokane, WA 99203	
(b) Leadership Consulting	
(c) Deferred	$13
Operating	$71,663
	$71,676
(a) R. W. Beck & Associates	
4th and Blanchard Building	
2121 Fourth Avenue	
Seattle, WA 98121	
(b) Consulting Engineers	
(c) Capital	$597,593
(a) Belles Consulting	
Mr. B. A. Belles	
8020 W. Rutter Parkway	
Spokane, WA 99208	
(b) Computer Consulting	
(c) Capital	$18,419
Operating	$16,135
	$34,554

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	Bison Environmental	
	Great Western Building	
	W. 905 Riverside, Suite 316	
	Spokane, WA 99201	
(b)	Environmental & Engineering Consulting	
(c)	Deferred	$16,913
	Capital	$1,281
	Operating	$45,151
		$63,345
(a)	Black & Veatch	
	P.O. Box 27-258	
	Kansas City, MO 64180	
(b)	Consulting Engineers	
(c)	Capital	$196,759
(a)	Bovay Northwest, Inc.	
	E. 808 Aprague Avenue	
	Spokane, WA 99202	
(b)	Consulting Engineers	
(c)	Operating	$64,476
	Capital	$9,366
	Deferred	$2,755
	Total	$76,597
(a)	Brinson Partners	
	209 South LaSalle Street, Suite 102	
	Chicago, IL 60604-1295	
(b)	Investment Consultants	
(c)	Deferred	$64,482
(a)	CH2M Hill	
	P.O. Box 91500	
	Bellevue, WA 98009-2050	
(b)	Environmental & Engineering Consulting	
(c)	Capital	$391,735
	Operating	$21,771
		$413,506

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	Citibank, N A		
	111 Wall Street		
	Sort 4889		
	New York, NY 10043		
(b)	Trustee Fees		
(c)	Deferred		$2,857
	Operating		$47,104
		Total	$49,961
(a)	Consumer Credit Counseling		
	Service of the Inland Empire		
	P.O. Box 5393		
	Spokane, Wa 99205-0393		
(b)	Credit Counseling		
(c)	Operating		$27,489
(a)	Cravath, Swaine & Moore		
	Worldwide Plaza		
	825 Eighth Avenue		
	New York, NY 10019		
(b)	Legal		
(c)	Deferred		$45,779
	Operating		$10,707
		Total	$56,486
(a)	David Evans & Associates		
	North 920 Washington, Suite 17		
	Spokane, WA 99201-2235		
(b)	Consulting Engineers		
(c)	Deferred		$9,234
	Capital		$68,869
		Total	$78,103

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	Deloitte & Touche	
	111 Third Avenue	
	Seattle, WA 98101	
(b)	Independent Accountants	
(c)	Operating	$14,602
	Capital	$415
	Deferred	$284,609
	Total	$299,626
(a)	Drake Beam Morin, Inc.	
	100 Park Avenue	
	New York, NY 10017	
(b)	Human Resources Consulting	
(c)	Deferred	$6,412
	Operating	$28,376
	Total	$34,788
(a)	Dunau Associates	
	624 E. 24th Avenue	
	Spokane, WA 99203	
(b)	Environmental & Engineering Consulting	
(c)	Operating	$53,264
(a)	Dylan Associates	
	W. 11511 Garfield Road	
	Spokane, WA 99204	
(b)	Environmental & Engineering Consulting	
(c)	Operating	$29,649
(a)	Ebasco Services, Inc.	
	210 Clay Avenue	
	Lyndhurst, NJ 07071	
(b)	Consulting Engineer	
(c)	Capital	$989,191
	Operating	$272,821
	Total	$1,262,012

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	E D S Credit Corporation P.O. Box 75791 Chicago, IL 60675	
(b)	Computer Services & Consulting	
(c)	Capital	$311,837
	Operating	$963,136
		$1,274,973
(a)	Grapic Environments 712 Wilshire Blvd. #1012 Santa Monica, CA 90401	
(b)	Computer Consulting	
(c)	Capital	$85,050
(a)	Michael J. Hanson 430 Public Service Bldg Portland, OR 97204	
(b)	Northwest Power Pool Consultant	
(c)	Deferred	$82,536
(a)	Jerry Jackson & Assoc. P.O. Box 2466 Chapel Hill, NC 27515	
(b)	Forecast Consulting	
(c)	Deferred	$195,880
	Operating	$475
	Total	$196,355
(a)	Howard Johnson & Company 1111 Third Avenue, Suite 1700 Seattle, Wa 98101	
(b)	Investment Consultants and Actuaries	
(c)	Operating	$66,982

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	Quinn Loucks 12871 Francine Terrace Poway, CA 92064		
(b)	Computer Consulting		
(c)	Capital		$61,420
(a)	Management Technologies, Inc. N. 111 Vista Road, Suite 4C Spokane, Wa 99212		
(b)	Human Resources Consulting		
(c)	Capital		$145
	Operating		$31,118
		Total	$31,263
(a)	Merrill Schultz & Associates 16400 Southcenter Parkway 300 Seattle, WA 98188		
(b)	Electric Utility Consultants		
(c)	Operating		$29,107
(a)	MW Consulting Engineers W. 222 Wall Street, Suite 200 Spokane, WA 99201		
(b)	Consulting Engineers		
(c)	Operating		$12,575
	Capital		$5,460
	Deferred		$29,238
		Total	$47,273
(a)	Moody's Investor Service P.O. Box 12086 Newark, NJ 07101		
(b)	Investment Consultants		
(c)	Operating		$35,882

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	Morrow & Co.		
	47 Lafayette Pl. IE		
	Greenwich, CT 06830		
(b)	Financial Consulting		
(c)	Operating		$80,756
(a)	Northrop Devine & Tarbell, Inc.		
	500 Washington Avenue		
	Portland, ME 04103		
(b)	Engineering & Environmental Science Consulting		
(c)	Operating		$37,554
(a)	Northwest Consulting Serv ice		
	P.O. Box 74		
	Dryden, WA 98821		
(b)	Consulting Engineers		
(c)	Capital		$26,169
	Operating		$8,947
		Total	$35,116
(a)	Pacific Construction Consultants		
	4156 148th Avenue NE		
	Redmond, WA 98052		
(b)	Auditing Services		
(c)	Operating		$46,357
(a)	Paine, Hamblen, Coffin, Brooke & Miller		
	717 W. Sprague, Suite 1200		
	Spokane, WA 99204		
(b)	Legal		
(c)	Operating		$1,426,067
	Capital		$230,864
	Deferred		$198,075
		Total	$1,855,006

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	Power Engineering, Inc. P.O. Box 1066 Hailey, ID 83333		
(b)	Consulting Engineers		
(c)	Capital		$37,348
	Operating		$19,833
		Total	$57,181
(a)	Reid & Priest 40 West 57th Street New York, NY 10019		
(b)	Legal		
(c)	Operating		$114,406
	Deferred		$107,019
		Total	$221,425
(a)	Robinson Research E. 130 Indiana, Suite B Spokane, WA 99207		
(b)	Environmental & Engineering Consulting		
(c)	Deferred		$4,410
	Operating		$29,954
		Total	$34,364
(a)	Rosen/Brown Direct Harbor Square 5410 SW Macadam, Suite 200 Portland, OR 97201		
(b)			
(c)	Deferred		$19,251
	Operating		$100,018
		Total	$119,269

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a) SSR Inc. Engineers
E. 1817 Springfield, Suite G
Spokane, WA 99202

(b) Engineering Consulting

(c) Capital		$49,984
Operating		$18,766
	Total	$68,750

(a) Robert B. Sheppard
30 Glacier Key
Bellevue, WA 98006

(b) Legal

(c) Operating $46,791

(a) Sullivan & Cromwell
125 Broad Street
New York, NY 10004

(b) Legal

(c) Operating $109,774

(a) Glenn Traeger
26 SW Salmon Street, Suite 400
Portland, OR 97204

(b) Northwest Power Pool Consultant

(c) Deferred $75,633

(a) Tucson Economic Consulting
7630 North Sultan Place
Tucson, AZ 85704

(b) Economic Consulting

(c) Operating $90,274

Name of Respondent	This Report Is:	Date of Report (Mo,Da, Yr)	Year of Report
The Washington Water Power Company	[X] An Original [ ] A Resubmission	April 30, 1993	Dec. 31, 1992

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES (Continued)

(a)	VPA Corporation 1768 Business Center Drive, Suite 120 Reston, VA 22090	
(b)	Computer Project Assessment	
(c)	Deferred	$4,186
	Capital	$50,947
	Total	$55,133
(a)	Washington Trust Bank Trust Department P.O. Box 2127 Spokane, WA 99210-2127	
(b)	Trustee Fees	
(c)	Deferred	$331,575
	Operating	$6,802
	Total	$338,377
(a)	White Runkle Zack P.O. Box 3868 Spokane, WA 99220	
(b)	Advertising Consultants	
(c)	Deferred	$39,017
	Operating	$709,663
	Total	$748,680
(a)	The Wyatt Company 1211 SW Fifth Avenue, Suite 2120 Portland, OR 97204	
(b)	Actuarial Consultants	
(c)	Deferred	$41,003
	Operating	$11,729
	Total	$52,732
(a)	Capital Trust River Forum, Suite 450 4380 SW Macadam Ave. Portland, OR 97201	
(b)	Trustee Fees	
(c)	Operating	$194,751

Sch. 14 POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

	Description	Total Company	Montana	% Montana
3	No payments were made for Political Contributions or to Political Action			
4	Committees in the State of Montana in 1992.			
53	TOTAL			

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	Actuarial Cost Method	Yes	Yes	
7				
8	Is the Plan overfunded?	Yes	Yes	
9				
10	Accumulated Benefit Obligation	(71,646,000)	(76,853,000)	
11	Projected Benefit Obligation	(89,780,000)	(95,446,000)	
12	Fair Value of Plan Assets	116,594,000	118,883,000	
13				
14	Discount Rate for Benefit Obligations	8.5%	8.5%	
15	Expected Long-Term Return on Assets	9.0%	9.0%	
16				
17	Net Periodic Pension Cost:			
18	Service Cost	2,614,000	2,846,000	
19	Interest Cost	7,064,000	7,390,000	
20	Return on Plan Assets	(21,933,000)	(12,257,000)	
21	Amortization of Transition Amount	12,586,000	886,000	
22	Amortization of Gains or Losses			
23	Total Net Periodic Pension Cost	331,000	(1,135,000)	
24				
25	Minimum Required Contribution			
26	Actual Contribution			
27	Maximum Amount Deductible			
28	Benefit Payments			
29				
30	Montana Intrastate Costs:	Not available by state		
31	Pension Costs			
32	Pension Costs Capitalized			
33	Accumulated Pension Asset (Liability) at Year End			
34				
35	Number of Company Employees:			
36	Covered by the Plan	1941	1961	1.03
37	Not Covered by the Plan			
38	Active	1,318	1,341	1.75
39	Retired	516	509	(1.36)

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	8.5	
5	Expected Long-Term Return on Assets	0	0	
6	Medical Cost Inflation Rate	12% ('93)	11% ('94)	1%
7	Actuarial 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	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)	35,496,000	35,369,000	(.35)
23	Fair Value of Plan Assets	502,000	823,000	63.94
24	List the amount funded through each funding method:			
25	VEBA	502,000	823,000	63.94
26	401(h)			
27	Other ____________			
28	Total amount funded			
29	*Assets reflected are estimated to cover current costs.			
30	List amount that was tax deductible for each type of funding:			
31	VEBA			
32	401(h)			
33	Other ____________			
34	Total amount that was tax deductible			
35				
36	Net Periodic Post Retirement Benefit Cost:			
37	Service Cost	1,012,000	1,156,000	14.22
38	Interest Cost	3,017,000	3,006,000	(.36)
39	Return on Plan Assets			
40	Amortization of Transition Obligation	1,774,000	1,769,000	(.28)
41	Amortization of Gains or Losses			
42	Total Net Periodic Post Retirement Benefit Cost	5,803,000	5,931,000	2.20
43				
44	Benefit Cost Expensed			
45	Benefit Cost Capitalized			
46	Benefit Payments			
47				
48	Number of Company Employees:			
49	Covered by the Plan	1941	1961	1.03
50	Not Covered by the Plan			
51	Active	1,318	1,341	1.75
52	Retired	516	509	(1.36)
53	Spouse/Dependants covered by the Plan	107	111	3.74

	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 or 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 EMPLOYEES (ASSIGNED OR ALLOCATED)

#	Name/Title	Base Salary*	Bonuses	Other	Total
1	J G Hanna Station Electrician-Noxon	59,047	796		59,843
	P J Aktepy Station Mechanic-Noxon	47,571	818		48,389
2	P A Kelly Journeyman Operator-Noxon	45,769	827		46,596
3	L L Wiltse, Jr Journeyman Operator-Noxon	45,406	828		46,234
	C F Webley Journeyman Operator-Noxon	45,258	799		46,057
4	W A Maxville, Jr Journeyman Operator-Noxon	45,110	819		45,929
	J L Gurner Journeyman Operator-Noxon	45,278	15		45,293
5	R G Robbins Journeyman Operator-Noxon	44,336	810		45,146
	T E Lampshire Journeyman Operator-Noxon	44,030	812		44,842
6	J L Gleason Journeyman Operator-Noxon	41,967	810		42,777
7					
8					
9					
10					

*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	1,473,446,409	1,560,411,029	5.90
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	39,819,744	32,739,289	(17.78)
11	108	(Less) Accumulated Depreciation	(388,297,295)	(424,294,941)	9.27
12	111	(Less) Accumulated Amortization	(6,625,378)	(4,354,870)	(34.27)
13	114	Electric/Gas Plant Acquisition Adjustment	26,623,872	28,350,517	6.49
14	115	(Less) Accum. Amortization of Gas Acquisition Adjustment	(321,000)	(1,698,315)	429.07
15	120	Nuclear Fuel			
16		TOTAL Utility Plant	1,144,646,352	1,191,152,709	4.06
17					
18	**Other Property & Investments**				
19					
20	121	Nonutility Property	15,735,138	2,776,135	(82.36)
21	122	(Less) Accum. Depr. & Amort. for Nonutility Property	(691,348)	(668,574)	(3.29)
22	123	Investments in Associated Companies			
23	123.1	Investments in Subsidiary Companies	72,520,523	79,615,886	9.78
24	124	Other Investments	125,163,219	117,975,658	(5.74)
25	125	Special Funds	4,396,343	6,710,857	52.65
26		TOTAL Other Property and Investments	217,123,875	206,409,962	(4.93)
27					
28	**Current & Accrued Assets**				
29					
30	131	Cash	(537,525)	59,878	111.14
31	132-134	Special Deposits			
32	135	Working Funds	112,055	103,897	(7.28)
33	136	Temporary Cash Investments	7,000,000	0	
34	141	Notes Receivable	59,728	117,701	97.06
35	142	Customer Accounts Receivable	26,431,065	24,607,087	(6.90)
36	143	Other Accounts Receivable	2,200,369	1,351,630	(38.57)
37	144	(Less) Accum. Provision for Uncollectible Accounts	(1,183,727)	(1,389,708)	17.40
38	145	Notes Receivable - Associated Companies			
39	146	Accounts Receivable - Associated Companies	3,848,702	3,769,575	(2.06)
40	151	Fuel Stock	4,631,979	4,933,418	6.51
41	152	Fuel Stock Expenses Undistributed	4,864	0	
42	153	Residuals			
43	154	Plant Materials and Operating Supplies	9,677,914	9,726,195	0.50
44	155	Merchandise			
45	156	Other Material Supplies		58,670	
46	157	Nuclear Materials Held for Sale			
47	163	Stores Expense Undistributed	(133,837)	(188,642)	40.95
48	164-165	Gas Storage Accounts and Prepayments	7,573,387	4,608,505	(39.15)
49	171	Interest & Dividends Receivable	404,782	52,619	(87.00)
50	172	Rents Receivable	827,395	897,302	8.45
51	173	Accrued Utility Revenues			
52	174	Miscellaneous Current and Accrued Assets	3,146,682	3,565,659	13.31
53		TOTAL Current and Accrued Assets	64,063,833	52,273,786	(18.40)

Sch. 18

BALANCE SHEET

Line	Account	Account Title	Last Year	This Year	% Change
1					
2		Assets & Other Debits (con't)			
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	4,734,169	4,719,661	(0.31)
7	182.1	Extraordinary Property Loses			
8	182.2	Unrecovered Plant & Regulatory Study Costs	9,844,707	7,477,218	(24.05)
9	183	Preliminary Survey & Investigation Charges	10,563,004	9,773,176	(7.48)
10	184	Clearing Accounts	133,132	(850,697)	(738.99)
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	17,662,924	29,454,141	66.76
13	187	Deferred Losses from Disposition of Utility Plant			
14	188	Research Development & Demonstration Expenditures	60,871	5,817	(90.44)
15	189	Unamortized Loss on Reacquired Debt	15,174,146	17,191,957	13.30
16	190-191	Accum. Def. Inc. Taxes & Unrecovered Purch. Gas Costs	21,367,129	27,081,406	26.74
17		TOTAL Deferred Debits	79,540,082	94,852,679	19.25
18					
19		TOTAL Assets & Other Debits	1,505,374,142	1,544,689,136	2.61

Line	Account	Account Title	Last Year	This Year	% Change
20					
21		Liabilities and Other Credits			
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	458,370,905	508,202,892	10.87
26	202	Common Stock Subscribed	125,000,000	135,000,000	8.00
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	(7,732,734)	(9,622,923)	24.44
33	215	Appropriated Rertained Earnings	1,548,121	1,548,121	0.00
34	216	Unappropriated Retained Earnings	93,499,262	100,095,710	7.06
35	217	(less) Reacquired Capital Stock			
36		TOTAL Proprietary Capital	670,685,554	735,223,800	9.62
37					
38	**Long Term Debt**				
39					
40	221	Bonds	372,800,000	297,800,000	(20.12)
41	222	(Less) Reacquired Bonds			
42	223	Advances From Associated Companies			
43	224	Other Lond Term Debt	258,322,107	299,280,043	15.86
44	225	Unamortized Premium on Long Term Debt	328,161	103,267	(68.53)
45	226	(Less) Unamort. Discount on Long Term Debt (Dr.)	(1,698,822)	(1,624,023)	(4.40)
46		TOTAL Long Term Debt	629,751,446	595,559,287	(5.43)

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	2,336,017	936,226	(59.92)
7	228.1	Accumulated Provision for Property Inurance			
8	228.2	Accumulated Provision for Injuries & Damages	900,101	1,437,593	59.71
9	228.3	Accumulated Provision for Pensions & Benefits			
10	228.4	Accmulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12		TOTAL Other Noncurrent Liabilities	3,236,118	2,373,819	(26.65)
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	27,780,337	27,524,989	(0.92)
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies			
20	235	Customer Deposits	912,555	931,667	2.09
21	236	Taxes Accruded	21,548,794	17,656,289	(18.06)
22	237	Interest Accrued	11,436,163	12,768,996	11.65
23	238	Dividends Declared		284,750	
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	388,264	571,950	47.31
27	242	Miscellaneous Current & Accrued Liabilities	11,038,415	11,639,956	5.45
28	243	Obligations Under Capital Leases - Current	1,297,196	1,460,867	12.62
29		TOTAL Current & Accrued Liabilities	74,401,724	72,839,464	(2.10)
30					
31	**Deferred Credits**				
32					
33	252	Customes Advances for Construction	2,290,632	3,426,162	49.57
34	253	Other Deferred Credits	13,590,245	13,294,291	(2.18)
35	255	Accumulated Deferred Investment Tax Credit	3,255,631	2,554,099	(21.55)
36	256	Deferred Gains from Disposition of Utility Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	108,162,792	119,418,214	10.41
39		TOTAL Deferred Credits	127,299,300	138,692,766	8.95
40					
41		TOTAL Liabilities & Other Credits	1,505,374,142	1,544,689,136	2.61

The Washington Water Power Company
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 11).

The accounting requirements of FERC as set forth in these financial statements differ from generally accepted accounting princples 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 1991 and 1992 as would be required under generally acceptable 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 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 1992, 1991 and 1990. 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 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 2.37% in 1992, 2.44% in 1991 and 2.50% in 1990.

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 1992, the Company deferred $3.3 million of net power supply costs, which resulted in like decreases in electric operating expenses. In 1991 and 1990, the Company deferred $1.8 and $2.5 million, respectively, of net power supply cost savings, which resulted in like increases in electric operating expenses. Rate changes are triggered when the deferred balance reaches $2.2 million. A rate increase was implemented in November 1992 to pass through accumulated costs. Rate reductions were implemented in May 1991 and May 1990, to pass through accumulated cost savings. As of December 31, 1992, $0.2 million of cost savings not yet subject to a rate reduction had accumulated in the PCA deferral account. The PCA is experimental and will end on June 30, 1993, unless extended by the IPUC.

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.

Investment Tax Credit

In 1990, $7,363,000 of deferred investment tax credits were recaptured related to the Company's Washington Public Power Supply System Project 3 investment.

Earnings Per Common Share

Earnings per common share have been computed based on the weighted average number of common shares outstanding during the period.

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. 109, entitled "Accounting for Income Taxes" was issued by the Financial Accounting Standards Board in February 1992, which supersedes FAS No. 96 and establishes revised financial accounting and reporting standards for the effects of income taxes. This Statement is effective for fiscal years beginning after December 15, 1992.

Implementation of FAS-109 in the first quarter of 1993 will create new regulatory assets estimated to be $154 million and offsetting deferred taxes in the Company's balance sheet relating to previously flowed through income taxes. The Company will file a request for an accounting order allowing the creation of the regulatory asset and offsetting deferred income liability, with the Washington Utilities and Transportation Commission (WUTC) and the IPUC. The regulatory assets and deferred tax liability will be amortized over the estimated remaining life of the associated plant. Creation of the regulatory assets and deferred tax liabilities is not expected to have any impact on the operating results of the Company.

As of December 31, 1992, the Company's tax provision reflects current tax reductions and deferrals in accordance with accounting requirements of regulatory authorities. Deferred income taxes have not been provided on certain book and tax timing differences which are expected to be recovered through rates. At December 31, 1992, the cumulative net amount of timing differences not provided for is approximately $154 million.

FAS No. 106, entitled "Employers Accounting for Postretirement Benefits Other Than Pensions", requires accruals for postretirement benefits (such as health care benefits) during the years an employee provides services to the Company. In addition, the new standard will require companies to record a liability for any unfunded obligation related to such benefits. Currently the Company records the cost of health care and life insurance benefits as they are actually paid to the retired employees. The cost of providing such benefits was $1,290,000, $1,233,000 and $1,151,000 for 1992, 1991 and 1990, respectively. Estimates indicate that under the new standard, the Company's initial unfunded liability would be approximately $35 million. Annual expense accruals would be approximately $6 million before taxes, including amortization of the unfunded liability. These estimates were developed assuming a 12% annual increase in health care costs for the first three years, with the increase rate decreasing thereafter to a 6.2% annual rate by 1997. A 1% change in these assumptions would change the estimated initial unfunded liability by approximate $2.4 million, and the estimated annual expense accruals by approximately $0.5 million. The Company adopted this Statement in 1993 and has received accounting orders from the WUTC and the IPUC allowing the current deferral of expense accruals under the new rule as a regulatory asset for future recovery. The new standard will not have any impact on actual cash outlays for these benefits, except to the extent that benefit plans are changed as a result of this standard or to the extent that the Company may decide to fund the liability.

FAS No. 107, entitled "Disclosures about Fair Value of Financial Instruments" was issued by the Financial Accounting Standards Board in December, 1991 for all financial statements issued after December 15, 1992. The following disclosure of the estimated fair value of financial instruments is made in accordance with FAS-107. The estimated fair value amounts have been determined by the Company, using available market information and appropriate valuation methodologies. However, considerable judgment is necessarily required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current market exchange. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

	December 31, 1992 (Thousands of Dollars)	
	Carrying Amount	Estimated Fair Value
Preferred Stock-Cumulative		
Subject to mandatory redemption		
Series I	$ 50,000	$ 54,000
Series K	35,000	35,350
Long-Term Debt:		
First mortgage bonds	293,700	296,216
Pollution control bonds	4,100	4,141
Unsecured medium-term notes	295,000	307,659
Notes payable and commercial paper	4,000	4,000
Other	97	97

NOTE 2. RETIREMENT PLANS AND OTHER POSTRETIREMENT BENEFITS

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 cost (credit) for 1992, 1991 and 1990 is summarized as follows:	1992	1991	1990
	(Thousands of Dollars)		
Service cost-benefits earned during the period	$ 2,846	$ 2,614	$ 2,334
Interest cost on projected benefit obligation	7,390	7,064	6,859
Actual return on plan assets	(12,257)	(21,933)	(874)
Net amortization and deferral	886	12,586	(9,331)
Net periodic pension cost (income)	(1,135)	331	(1,012)
Less amounts charged (credited) to construction and other accounts	(24)	115	(343)
Less regulatory adjustments to operating expenses (1)	0	321	(452)
Net pension cost charged (credited) to operating expenses	$ (1,111)	$ (105)	$ (217)

(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 Plans and the prepaid pension cost (pension liability) recognized in the Company's Balance Sheets at December 31, 1992, 1991 and 1990, are as follows:

	1992	1991	1990
	(Thousands of dollars)		
Actuarial present value of benefit obligations:			
Accumulated benefit obligations (including vested benefits of $(76,226,000), $(71,113,000) and $(70,451,000), respectively)	$ (76,853)	$ (71,646)	$ (70,672)
Projected benefit obligation for service rendered to date	$ (95,446)	$ (89,780)	$ (86,866)
Plan assets at fair value	118,883	116,594	100,562
Plan assets in excess of projected benefit obligation	23,437	26,814	13,696
Unrecognized net (gain) loss from returns different than assumed	(19,733)	(22,698)	(8,691)
Prior service cost not yet recognized in pension cost	8,568	8,107	8,635
Unrecognized net asset at year-end (being amortized over 11 to 19 years)	(13,531)	(14,617)	(15,703)
Regulatory deferrals	(1,381)	(131)	(452)
Prepaid pension cost (pension liability) included in Balance Sheets	$ (2,640)	$ (2,525)	$ (2,515)
Assumptions used in calculations were:			
Discount rate at year end	8.5%	8.5%	8.5%,
Rate of increase in future compensation level	5.0%	5.0%	5.0%
Expected long-term rate of return on assets	9.0%	9.0%	9.0%

NOTE 3. 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, 1992, including the January 8, 1993, early redemption of $50,000,000 of First Mortgage Bonds, are as follows:

Year Ended December 31	Maturities	Sinking Fund Requirements	Total
		(Thousands of Dollars)	
1993	$100,000	$2,437	$102,437
1994	50,000	2,137	52,137
1995	45,000	2,037	47,037
1996	20,000	1,837	21,837
1997	20,000	1,837	21,837

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.

On January 8, 1993, the $50,000,000 of 10 3/8% First Mortgage Bonds due in 2018 were redeemed at 107.49% of its principal amount.

As of December 31, 1992, the Company had authorization to issue up to $200,000,000 in aggregate principal amount of unsecured Medium-Term Notes, Series A and $150,000,000 of unsecured Medium-Term Notes, Series B (Notes). The Notes may be issued from time to time and may vary in term from 9 months to 30 years. In 1992, 1991 and 1990, $113,000,000, $37,000,000 and $75,000,000, respectively, of these Notes were issued. At December 31, 1992, the Company had outstanding $295,000,000 of the Notes with maturities between 3 and 30 years and with interest rates varying between 7.94% and 10.06%. On January 15, 1993, the $10,000,000 of 8.65% Medium Term Notes matured and were paid. In February 1993, the Company issued an additional $20 million in Series B Medium Term Notes.

At December 31, 1992, the Company had $4,000,000 outstanding under borrowing arrangements which will be refinanced in 1993. See Note 4 for details of credit agreements.

NOTE 4. BANK BORROWINGS AND COMMERCIAL PAPER

At December 31, 1992, 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 expiring September 29, 1993 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,		
	1992	1991	1990
		(Dollars in thousands)	
Balance outstanding at end of period:			
Fixed-term loans	$ 4,000	$ 13,000	$ -
Commercial paper	-	3,000	-
Revolving credit agreement	-	30,000	-
Maximum balance during period:			
Fixed-term loans	$ 26,000	$ 20,000	$ -
Commercial paper	24,000	20,805	13,000
Revolving credit agreement	30,000	34,000	10,000
Average daily balance during period:			
Fixed-term loans	$ 9,989	$ 3,797	$ -
Commercial paper	7,351	4,131	11,337
Revolving credit agreement	7,212	4,250	1,081
Average annual interest rate during period:			
Fixed-term loans	4.26%	5.48%	-%
Commercial paper	4.18	5.51	8.46
Revolving credit agreement	4.19	5.43	8.45
Average annual interest rate at end of period:			
Fixed-term loans	4.43%	5.34%	-%
Commercial paper	-	5.55	-
Revolving credit agreement	-	5.28	-

NOTE 5. ACCOUNTS RECEIVABLE SALE

In February 1988, the Company entered into an agreement whereby it can sell, on a revolving basis, up to $30,000,000 of interests in certain accounts receivable, both billed and unbilled. On December 16, 1992, the agreement was amended to sell up to $40,000,000 of accounts receivable. 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 December 31, 1992 and 1991, $40,000,000 and $30,000,000, respectively, in receivables had been sold pursuant to the agreement.

NOTE 6. PREFERRED STOCK

Cumulative Preferred Stock Not Subject to Mandatory Redemption:
During 1990, the Company sold 500 shares of Flexible Auction Preferred Stock, Series J at a price of $100,000 per share. The dividend rate on this series is reset every 49 days based on an auction. During 1992, the dividend rate varied from 3.09% to 4.26% and at December 31, 1992, was 4.02%. 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 $20 million in mandatory redemption requirements during the 1993-1997 period.

On March 13, 1992, the Company redeemed its $9.00 Series A Preferred Stock. The redemption price for the $25 million was $102.70 per share plus an amount equivalent to the accumulated but unpaid dividends to the date of redemption.

NOTE 7. COMMON STOCK

In April 1990, the Company sold 500,000 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 ($13,188,250 at December 31, 1992) 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 1992, the cost recorded for the Plan was $2,056,000. This included the cost for an additional 93,362 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 $1,276,000, $1,634,000 and $1,235,000, 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 $80, 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 750,000 shares of Common Stock under a Periodic Offering Program (POP). During the first half of 1992, the remaining 553,800 shares of the first POP were issued under this program for proceeds of $18.0 million. In the second half of 1992, the Company received authorization to issue a second 750,000 shares of common stock under the POP. Through December 31, 1992, 175,600 shares of the second POP were issued for proceeds of $6.0 million.

The Company has an Employees' Stock Purchase Plan which provides for the granting to all regular employees of the Company and its principal subsidiaries, during such limited offering periods as may be specified from time to time by the Board of Directors, the right to purchase a limited number of shares of the Company's Common Stock. No shares have been issued under this Plan since 1987. In addition, 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 1992, 1991 and 1990, are summarized below (dollar amounts in thousands):

	1992		1991		1990	
	Shares	Amount	Shares	Amount	Shares	Amount
Balance at January 1	23,950,801	$458,371	23,211,913	$434,936	22,330,580	$409,825
Employee Investment Plan (401-K)	93,362	3,147	75,230	2,317	528,147	14,931
Dividend Reinvestment Plan	670,502	22,721	467,458	14,551	353,186	10,180
Periodic Offering	729,400	23,963	196,200	6,567	-	-
Total Issues	1,493,264	49,831	738,888	23,435	881,333	25,111
Balance at December 31	25,444,065	$508,202	23,950,801	$458,371	23,211,913	$434,936

NOTE 8. FEDERAL INCOME TAXES

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

NOTE 9. 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. An after tax gain on the sale of $13.5 million was recorded in 1990. A tax adjustment of $1.6 million related to the sale was recorded in 1991. The 1992 net income 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.

Condensed financial information of WIDCo related to discontinued coal mining operations is presented below based on financial statements for the years ended December 31, 1992, 1991 and 1990.

	1992	1991	1990
		(Thousands of Dollars)	
Statements of Operations:			
Operating revenues	$ -	$ -	$ 34,687
Operating expenses	-	-	29,654
Income from operations	-	-	5,033
Interest expense and other	2,403	-	1,351
Income before income taxes	2,403	-	3,682
Income taxes(a)	-	-	1,690
Net income before gain on asset sale	2,403	-	1,992
Net gain on sale of assets	-	1,553	13,465
Net income before preferred dividends	$ 2,403	$ 1,553	$15,457

(a) The provision for federal income tax is different from that which would be computed by applying the statutory tax rate to income before income tax due to the use of percentage depletion of mineral properties.

NOTE 10. 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 started receiving, in 1987, power deliveries from BPA 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 the event BPA elects to complete Project 3, the Company expects that BPA would initiate a resource acquisition process in accordance with the Regional Power Act. Under such an acquisition, the ultimate financial responsibility for completing and financing the acquired capability would be assumed by BPA. Under certain circumstances, the Company could be required to issue its own securities to finance its share of the costs of completion of Project 3 but would be reimbursed by 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, 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.

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. If it is assumed that the entire amount claimed to be subject to reallocation by Chemical Bank is equally divided between Projects 4 and 5, the Company's maximum exposure would be approximately $25 million, including the interest Chemical Bank claims from the commencement of construction. Since Chemical Bank's claim includes interest, the total amount of the claim continues to increase over time. 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.

Other Contingencies

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 seeks actual and punitive damages of $208 million. The case is in the early stages of discovery and is not yet set for trial. While the Company cannot predict the outcome of this litigation, at this time the Company does not believe that the outcome will have a material effect on its financial condition.

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 12.

NOTE 11. 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, 1992:

			Company's Current Share of				
Project	KW of Installed Capacity	Fuel Source	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%	$ 53,815	$27,399	$ 26,416	$475
Colstrip 3 & 4	1,400,000	Coal	15	268,618	64,283	204,335	-

NOTE 12. 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, 1992, pertaining to these contracts is summarized in the following table:

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs(b)	Debt Service Costs(c)	Revenue Bonds Outstanding	Contract Expiration Date
Public Utility District (PUD) Contracts:				(Thousands of Dollars)		
Chelan County PUD:						
Lake Chelan Project	100.0% (a)	58,000	$ 3,309	$ 799	$ 3,710	1995
Rocky Reach Project	2.9	37,000	967	519	5,485	2011
Grant County PUD:						
Priest Rapids Project	6.1	55,000	1,378	948	8,837	2005
Wanapum Project	8.2	75,000	1,942	1,254	16,127	2009
Douglas County PUD:						
Wells Project	3.6	30,000	837	555	7,507	2018
Totals		255,000	$ 8,433	$ 4,075	$ 41,666	

(a) 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.
(b) 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 1992.
(c) Included in annual costs.

Actual expenses for payments made under the above contracts for the years 1992, 1991 and 1990, were $8,433,000, $7,589,000 and $7,607,000, 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 $4,374,000 in 1993, $4,279,000 in 1994, $4,401,000 in 1995, $3,216,000 in 1996, $3,764,000 in 1997 (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 13. ACQUISITIONS

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, 1995, 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. For the period September 30, 1991, through December 31, 1991, WP Natural Gas operating revenues were $12.4 million and operating income (before income taxes) was $4.4 million. The Company believes that this acquisition will not have a material impact on its revenues or its operations.

In December 1992, the Company completed the purchase of the north 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 February 28, 1992, ITRON, Inc. (ITRON), previously a majority-owned subsidiary of Pentzer Corporation (Pentzer), completed its announced acquisition of EnScan, Inc., a wholly owned subsidiary of Arkla, Inc. of Shreveport, Louisiana, in exchange for 23% (approximately 8 million shares) of ITRON's common stock. This reduced Pentzer's common stock ownership interest in ITRON to approximately 40%. Accordingly, Pentzer's share of ITRON's earnings is accounted for by the equity method and is reflected in Other Income-Net. Pentzer's investment in ITRON is reflected on the balance sheet under Other Property and Investments for 1992. As a result, there is no longer any other minority interest in ITRON reflected in the financial statements. In March 1992, Pentzer recorded a gain of $6.7 million ($4.4 million or $.18 per share on an after-tax basis) due to ITRON's issuance of common stock to acquire EnScan, Inc. EnScan, Inc. is a supplier of automated meter reading systems to utilities and uses a proprietary radio technology in the manufacturing of a product used to remotely collect utility meter readings.

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
303 Miscellaneous Intangible Plant		34,006	100.00
TOTAL Intangible Plant	193,078	227,084	14.98
Production Plant			
Steam Production			
310 Land & Land Rights	1,304,876	1,304,594	(0.02)
311 Structures & Improvements	98,710,863	98,905,194	0.20
312 Boiler Plant Equipment	113,810,062	113,994,988	0.16
313 Engines & Engine Driven Generators			
314 Turbo Generator Units	22,964,558	23,412,215	1.91
315 Accessory Power Plant Equipment	13,386,179	13,387,393	0.01
316 Miscellaneous Power Plant Equipment	11,741,743	11,836,724	0.80
TOTAL Steam Production Plant	261,918,281	262,841,108	0.35
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	9,854,606	9,961,609	1.09
332 Resevoirs, Dams and Waterways	30,337,547	30,756,391	1.38
333 Water Wheels, Turbines and Generators	28,682,836	28,735,191	0.18
334 Accessory Electric Eqipment	1,964,973	2,464,885	25.44
335 Miscellaneous Power Plant Equipment	1,116,982	1,363,299	22.05
336 Road, Railroads & Bridges	88,694	88,694	0.00
TOTAL Hydraulic Production Plant	109,963,152	111,287,583	1.20

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	371,881,433	374,128,691	0.60
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	13,494,599	14,184,882	5.12
354 Towers & Fistures	15,986,603	15,986,603	0.00
355 Poles & Fixtures	6,714,011	6,715,953	0.03
356 Overhead Conductors and Devices	15,647,371	15,688,188	0.26
357 Underground Conduit			
358 Underground Conductors & Devices			
359 Roads & Trails	367,477	367,477	0.00
TOTAL Transmission Plant	53,223,972	53,957,014	1.38
Distribution Plant			
360 Land & Land Rights	15,881	15,881	0.00
361 Structures & Improvements	132,818	132,818	0.00
362 Station Equipment			
363 Storage Battery Equipment	8,955	8,955	0.00
364 Poles, Towers and Fixtures	6,676	6,676	0.00
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	166,067	0.00

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	3,717	0.00
7	392 Transportation Equipment	31,860	80,259	151.91
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	2,327,144	2,378,160	2.19
13	398 Miscellaneous Equipment	290	290	0.00
14	399 Other Tangible Property			
15				
16	TOTAL General Equipment	2,583,931	2,683,346	3.85
17				
18	TOTAL Electric Plant in Equipment	428,048,481	431,162,202	0.73

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	74,669,878	72,184,499	3.44
6	Depreciation	41,494,082	37,647,369	10.22
7	Amortization	14,804,367	13,830,377	7.04
8	Deferred Income Taxes - Net	14,880,420	6,523,440	128.11
9	Investment Tax Credits - Net	(701,532)	(1,458,922)	51.91
10	Change in Operating Receivables - Net	(4,947,378)	690,550	(816.44)
11	Change in Materials, Supplies & Inventories - Net	1,046,913	(2,134,247)	149.05
12	Change in Operating Payable & Accrued Liabilities - Net	(1,352,441)	11,694,140	111.57
13	Allowance for Funds Used During Construction (AFUDC)	(1,391,562)	(1,135,706)	(22.53)
14	Change in Assets and Liabilities - Net			
15	Other Operating Activities (explained on attached page)	(19,900,132)	(12,124,269)	(64.13)
16	Net Cash Provided by/(Used in) Operating Activities	118,602,615	125,717,231	(5.66)
17				
18	**Cash Inflows/Outflows From Investment Activities**			
19	Construction/Acquisition of Property, Plant and Related Equipment	(76,158,946)	(126,707,484)	39.89
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)	(16,816,510)	(20,008,694)	15.95
27	Net Cash Provided by/(used in) Investing Activities	(92,975,456)	(146,716,178)	36.63
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	113,000,000	37,000,000	205.41
32	Preferred Stock	35,000,000		
33	Common Stock	49,831,987	23,434,587	112.64
34	Other: Accounts Receivable Sale	10,000,000		
35	Net Increase (Decrease) in Short-Term Debt	(42,000,000)	46,000,000	(191.30)
36	Other: Notes Receivable-ESOP	380,750	332,500	14.51
37	Payment for Retirement of:			
38	Long-Term Debt	(105,000,000)	(8,842,000)	(1,087.51)
39	Preferred Stock	(25,000,000)		
40	Common Stock			
41	Other:			
42	Net Decrease in Short-Term Debt	(42,064)	(218,854)	80.78
43	Dividends on Preferred Stock	(6,683,481)	(9,112,640)	36.35
44	Dividends on Common Stock	(61,525,126)	(58,697,156)	4.60
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	(32,037,934)	29,896,437	(207.16)
47				
48				
49	**Net Increase/Decreses in Cach and Cash Equivalents**	(6,410,775)	8,897,490	(172.05)
50	**Cash and Cash Equivalents at Beginning of Year**	6,574,530	(2,322,690)	383.06
51	**Cash and Cash Equivalents at End of Year**	163,775	6,574,530	(97.51)

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	(10,695,362)	(2,973,505)	(259.69)
6	Idaho Accretion Income	(426,750)	(460,127)	7.25
7	Change in Dividend Declared	(284,750)	520,835	(154.67)
8	Non-Monetary Power Transactions	(418,978)	(2,123,800)	80.27
9	Regulatory gas cost and power cost adjustment	(11,523,200)	(10,171,567)	(13.29)
10	Other Changes-Net	3,448,908	3,083,895	11.84
11	Total Line 15	(19,900,132)	(12,124,269)	(64.13)
12				
13				
14	**Line 26: Other Investing Activities**			
15	Additions in Non-Utility Plant	(12,959,003)	(14,517,870)	(10.74)
16	Other Capital Requirements	(10,944,454)	(5,124,524)	(113.57)
17	Dividends Received from Subsidiary Companies	3,600,000	3,600,000	
18	Changes in Noncurrent Balance Sheet Accounts	5,836,461	(1,756,799)	432.22
19	Other Special Funds	(2,349,514)	(2,209,501)	(6.34)
	Total Line 26	(16,816,510)	(20,008,694)	15.95

Sch. 2 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	First Mortgage Bonds								
2	4 5/8% Series	4/1/64	9/1/94	30,000,000	29,661,228	30,000,000	4.70	1,398,641	4.72
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	6% Series	8/1/66	8/1/96	20,000,000	19,895,008	20,000,000	6.04	1,203,727	6.05
5	7 7/8% Series	5/1/93	5/1/03	20,000,000	20,039,423	20,000,000	7.86	1,583,680	7.90
6	7 1/8% Series	12/1/89	12/1/13	66,7000,000	63,614,202	66,700,000	7.54	4,795,647	7.54
7	7 2/5% Series	12/1/89	12/1/16	17,000,000	16,418,069	17,000,000	7.70	1,267,552	7.72
8	9 1/4% Series	12/1/86	12/1/16	80,000,000	66,017,187	80,000,000	11.30	7,432,604	11.26
9	10 3/8% Series	1/12/88	11/1/18	50,000,000	46,840,000	50,000,000	11.11	5,207,312	11.12
10	Pollution Control	12/18/84	12/1/14	4,100,000	3,913,000	4,100,000	11.02	435,402	11.13
11									
12									
13									
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31									
32									
33	TOTAL			297,800,000	276,309,520	297,800,000			

Sch. 2

PREFERRED STOCK

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	Flexible Auction									
2	series "J"	variable	500	$100,000.	-	47,464,920	variable	50,000,000	variable	
3	series "I"	4/26/90	500,000	$100	-	46,508,204	8.625	50,000,000	4,312,500	9.27
4	series "K"	9/15/92	350,000	$100	-	32,902,560	6.950	35,000,000	2,432,500	7.39
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32										
33	TOTAL					126,875,684		135,000,000		

Sch. COMMON STOCK

	Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	24,022,232	22.61				34.000	32.000	12.65
February	24,174,711	22.28				33.500	32.625	12.62
March	24,354,466	22.74	.99	.62		33.000	31.875	12.09
April	24,544,676	22.97				33.625	32.250	12.94
May	24,719,911	22.56				34.125	33.000	13.30
June	24,841,885	22.90	.59	.62		34.250	32.750	13.25
July	24,918,446	23.04				35.500	33.375	13.98
August	24,957,429	22.58				36.750	34.125	12.55
September	25,041,361	22.71	.33	.62		34.625	34.125	13.22
October	25,152,750	22.94				35.000	34.625	13.11
November	25,222,381	22.53				35.375	34.000	12.64
December	25,330,829	23.07	.83	.62		35.500	34.000	12.86
TOTAL Year End	24,775,174		$2.74	$2.48	9.5%	35.250		

Sch. L.

OTHER CAPITAL

	Description	Outstanding Per Balance Sheet	Cost%	Weighted Cost%
1				
2	Unsecured Medium Term Notes- Series A	170,000,000	7.94%-10.06%	9.28%
3	Unsecured Medium Term Notes- Series B	125,000,000	6.04%- 8.55%	7.60%
4	Notes Payable and Commercial Paper to be refinanced	4,000,000		
5	Other	97,000		
6				
7				
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32				
33	TOTAL	295,000,000		

Sch. 28 MONTANA EARNED RATE OF RETURN

Line	Account	Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service			
3	108	(Less) Accumulated Depreciation			
4		NET Plant in Service			
5					
6		Additions			
7	154, 156	Materials & Supplies			
8	165	Prepayments			
9		Other Additions			
10		TOTAL Additions			
11					
12		Deductions			
13	190	Accumulated Deferred Income Taxes			
14	252	Customer Advances for Construction			
15	255	Accumulated Def. Investment Tax Credits			
16		Other Deductions			
17		TOTAL Deductions			
18		TOTAL Rate Base			
19					
20		Net Earnings			
21					
22		Rate of Return on Average Rate Base			
23					
24		Rate of Return on Average Equity			
25					
26		Major Normalizing Adjustments & Commission			
27		Ratemaking adjustments to Utility Operations			

The Company has 18 customers with 1992 revenues of $2,062,617 in the State of Montana. Rates charged were based on the Company's last rate order from the Idaho Public Utilities Commission and accepted by the Montana Commission. The Company does not calculate separate rate of return for the Montana jurisdiction.

Line	Description	Last Year	This Year	% Change
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
	Plant (Intrastate Only)	
101	Plant in Service	431,162,202
107	Construction Work in Progress	1,194,025
114	Plant Acquisition Adjustments	-
105	Plant Held for Future Use	-
154, 156	Materials & Supplies	2,735,590
	(Less):	
108, 111	Depreciation & Amortization Reserves (Production Only)	70,797,814
252	Contributions in Aid of Construction	-
	NET BOOK COSTS	364,294,003
	Revenues & Expenses (Intrastate Only)	
400	Operating Revenues	2,062,617
403 – 407	Depreciation & Amortization Expenses	8,545,149
409	Federal & State Income Taxes (State Only, Fed. Not Alloc)	853,580
408	Other Taxes	8,145,463
	Other Operating Expenses	33,757,232
	TOTAL Operating Expenses	51,301,424
	Net Operating Income	(49,238,807)
415–421.1	Other Income	
421.2–426.5	Other Deductions	
	NET INCOME (LOSS)	(49,238,807)
	Customers (Intrastate Only)	
	Year End Average:	
	Residential	12
	Commercial	5
	Industrial	
	Other	1
	TOTAL NUMBER OF CUSTOMERS	18
	Other Statistics (Intrastate Only)	
	Average Annual Residential Use (Kwh)	18,543
	Average Annual Residential Cost per (Kwh) (Cents) *	4.71
	* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
	Average Residential Monthly Bill	72.82
	Gross Plant per Customer	35,930,184

Sch. 30 MONTANA CUSTOMER INFORMATION

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1						
2	Noxon, MT		12	5		17
3						
4	Hot Springs, MT(Secondary Sales for Resale to Montana Power Co.				1	1
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32						
33	TOTAL Montana Customers		12	5	1	18

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

Sch. 32 MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)

	Project Description	Total Company	Total Montana
1	1993 Construction Budget		
2	Noxon Switch Yard-Improve Grounding		73,800
3	Colstrip-Various Additions		1,451,000
4	Noxon Generating Station-Rewind Unit #2		800,000
5	Noxon Switch Yard-Replace 230Kv Control Cables		300,000
6	Noxon Switch Yard-Replace HotSprings Line Relays		75,000
53	TOTAL		2,699,800

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.	22	0800	1309	1,031,348	278,856
2	Feb.	5	0800	1269	921,736	290,824
3	Mar.	5	0800	1158	875,988	251,801
4	Apr.	7	0900	1132	808,993	202,477
5	May	1	0800	1042	905,233	310,958
6	Jun.	23	1400	1166	759,523	183,514
7	Jul.	30	1200	1120	775,995	211,336
8	Aug.	19	1600	1185	820,353	187,265
9	Sep.	14	900	1051	795,071	233,019
10	Oct.	15	800	1166	889,755	286,841
11	Nov.	25	800	1343	975,389	274,760
12	Dec.	4	800	1435	1,042,651	208,294
13	TOTAL				10,602,035	2,919,945
		Montana				
		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale
14	Jan.	N/A	N/A	N/A	57	6807
15	Feb.	"	"	"	42	2365
16	Mar.	"	"	"	40	6816
17	Apr.	"	"	"	38	1076
18	May	"	"	"	18	10382
19	Jun.	"	"	"	59	4320
20	Jul.	"	"	"	31	585
21	Aug.	"	"	"	18	1155
22	Sep.	"	"	"	26	560
23	Oct.	"	"	"	24	1070
24	Nov.	"	"	"	30	12160
25	Dec.				26	0
26	TOTAL				409	47296

Sch. 34	TOTAL SYSTEM Sources & Disposition of Energy			
	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	3301,801	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	6,920,831
4	Hydro – Conventional	2969,462		
5	Hydro – Pumped Storage		Requirements Sales	
6	Other	8,630	for Resale	273,201
7	(Less) Energy for Pumping			
8	NET Generation	6,279,963	Non-Requirements Sales	
9	Purchases	4,250,352	for Resale	2,889,246
10	Power Exchanges			
11	Received	1,301,672	Energy Furnished	
12	Delivered	1,229,952	Without Charge	
13	NET Exchanges			
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	3543,948	Electric Utility	
16	Delivered	3543,948		
17	NET Transmission Wheeling	0	Total Energy Losses	518,757
18	Transmission by Others Losses			
19	TOTAL	10,602,035	TOTAL	10,602,035

Sch. 35	SOURCES OF ELECTRIC SUPPLY			
Type	Plant Name	Location	Annual Peak	Annual Energy
Washington			Megawatts	Megawatthours
Thermal	Centralia	Centralia, WA	198	1,328,016
Thermal	Kettle Falls	Kettle Falls, WA	59	291,630
Hydro	Little Falls	Ford, WA	36	169,454
Hydro	Long Lake	Ford, WA	72	390,554
Hydro	Meyers Falls	Colville, WA	1.2	5,844
Hydro	Monroe Street	Spokane, WA	15	17,326
Hydro	Nine Mile	Nine Mile Falls, WA	19	104,333
Hydro	Upper Falls	Spokane, WA	11	71,284
Comb. Turbine	Northeast	Spokane, WA	56	8,630
	Total Washington			2,387,071
Idaho				
Hydro	Cabinet Gorge	Clark Fork, ID	229	848,349
Hydro	Post Falls	Post Falls, ID	18	79,098
	Total Idaho			927,447
Montana				
Thermal	Colstrip #3 & #4	Colstrip, Montana	218	1,682,225
Hydro	Noxon	ThompsonFalls, Montana	512	1,283,220
	Total Montana			2,965,445
Total System				6,279,963
Total				

Sch. 36 MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT 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							
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