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PUBLIC SERVICE
COMMISSION

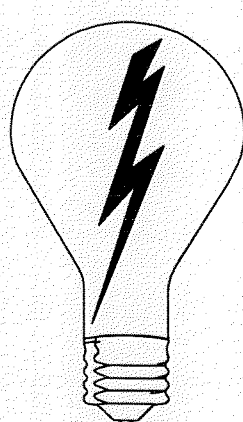
YEAR 1995

ANNUAL REPORT

OF

PACIFICORP dba Pacific Power

ELECTRIC UTILITY



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

Check No. 0310736
2-16-96

Revised November 9, 1994

Electric Annual Report

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Electric Annual Report

Instructions

General

1. A computer disk, formatted with DOS Version 6.0, is being provided for your convenience. The files were created using the DOS version of Lotus 5.0 and were saved with the wk3 extension. Separate files were created for each page. Where multiple schedules are on one page, one file was created. The naming convention of the files is representative of the schedules contained on a page (for example, Schedules 1 and 2 are sch1&2.wk3, Schedule 3 is sch3.wk3). Use of the disk is optional. The disk shall be returned when the report is filed.

2. All forms shall be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed.

3. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses (   ).

4. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

5. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

6. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

7. All companies owned by another company shall attach a corporate structure chart of the holding company.

8. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

9. The following schedules shall be filled out with information on a total company basis:

Schedules 1 through 5
Schedules 6 and 7
Schedule 14
Schedule 17 and 18
Schedules 23 through 26
Schedules 33 and 34

All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

10. FERC Form-1 sheets may not be substituted in lieu of completing annual report schedules.

11. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 101 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

Schedule 12

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form. Lines 17 through 30 shall be filled out using FASB 87 guidelines. Line 32 refers to the minimum required contribution under ERISA. Line 34 refers to the maximum amount deductible for tax purposes.

3. Interest rate percentages (lines 21 and 22) shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 16 through 19. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 16 through 19. All assumptions used in quantifying cost containment results shall be disclosed.

2. Lines 36 through 46 on page 1 and lines 18 through 28 on page 2 shall be filled out using FASB 106 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

3. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 31

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 32

1. Provide a written narrative detailing the sources and amounts of electric supply at the time of the annual peak.

Schedule 34

1. The following categories shall be used in the Type column: Thermal, Hydro, Nuclear, Solar, Wind, GeoThermal, Qualifying Facility (QF), Independent Power Producer (IPP), Off System Purchases, or Other. Spot market purchases shall be separately identified. Entries for the Other category shall be listed as separate line items and include a description.
   Note: For Off System Purchases, the Utility/Company whom the purchases are being made from shall be entered in the Plant Name column, the termination date of the purchased power contract shall be entered in the Location column.

2. Provide a written narrative of all outages exceeding one hour which occurred during the year. Explain the reason for the outage. If routine maintenance schedules are exceeded, explain the reason.

Schedule 35

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

Sch. 1 IDENTIFICATION

Legal Name of Respondent:	PacifiCorp
Name Under Which Respondent Does Business:	Pacific Power / Utah Power
Date Utility Service First Offered in Montana:	May 21, 1954 (Date of Mountain States Power Company merger with Pacific Power)
Person Responsible for Report:	Anne E. Eakin - Assistant Vice President
Telephone Number for Report Inquiries:	(503) 464-5065
Address for Correspondence Concerning Report:	Pacific Power 1228 Public Service Building 920 S. W. Sixth Avenue Portland, Oregon 97204

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	Keith R. McKennon (Chairman)	Portland, Oregon	155,000
2	A. M. Gleason (Vice Chairman) (1)	Portland, Oregon	(2)
3	Frederick W. Buckman (3)	Portland, Oregon	(2)
4	C. M. Bishop, Jr. (4)	Portland, Oregon	22,433
5	Kathryn A. Braun	Irvine, Californiz	41,689
6	C. Todd Conover	Cupertino, California	53,470
7	Richard C. Edgley	Salt Lake City, Utah	65,975
8	John C. Hampton (5)	Portland, Oregon	59,996
9	Nolan E. Karras	Roy, Utah	58,759
10	Robert G. Miller	Portland, Oregon	40,746
11	Verl R. Topham	Salt Lake City, Utah	(2)
12	Don M. Wheeler	Salt Lake City, Utah	54,473
13	Nancy Wilgenbusch	Marylhurst, Oregon	46,246
14	Peter I. Wold (6)	Casper Wyoming	21,639
15			
16			
17			
18	(1) Resigned May 1995.	(5) Retire February 1996.	
19	(2) No remuneration as a director, officer of the	(6) Elected May 1995.	
20	Company during 1993		
21	(3) President and Chief Executive Officer of the		
22	Company.		
23	(4) Retired February 1995		

Sch. 3

OFFICERS

	Title	Department Supervised	Name
1	President and Chief Executive Officer		Frederick W. Buckman
2			
3	Vice Chairman		A. M. Gleason (1)
4			
5	Senior Vice President		Paul G. Lorenzini
6			
7	Senior Vice President and General Counsel		Verl R. Topham
8			
9	Senior Vice President and Chief Financial Officer		William J. Glasgow (2)
10			
11	Senior Vice President		Daniel L. Spalding
12			
13	Senior Vice President		John A. Bohling
14			
15	Senior Vice President		John E. Mooney
16			
17	Senior Vice President		Shelley R. Faigle
18			
19	Senior Vice President		Dennis P. Steinberg
20			
21	Senior Vice President and Chief Financial Officer		Richard T. O'Brien (3)
22			
23	Vice President		William C. Brauer
24			
25	Vice President		Brett Harvey
26			
27	Vice President		David P. Hoffman
28			
29	Vice President		Thomas J. Imeson
30			
31	Vice President		Robert F. Lanz
32			
33	Vice President and Corporate Secretary		Sally A. Nofziger
34			
35	Vice President		Edwin J. O'Mara
36			
37	Vice President		Michael J. Pittman
38			
39	Vice President		Paul Pechersky (4)
40			
41	Vice President		Ernest E. Wessman
42			
43	Vice President		Thomas W. Forsgren
44			
45	Vice President		Thomas A. Lockhart
46			
47	Vice President		Richard D. Westerberg
48			
49	Vice President		Michael C. Henderson (5)
50			

Sch. 3

OFFICERS

Title	Department Supervised	Name
Controller		Jacqueline S. Bell
Treasurer		William E. Peressini
Controller - Electric Operations, Assistant Secretary		H. Arnold Wagner

(1) Elected Vice Chairman of the board effective February 1, 1994, resigned effective May 1, 1995.
(2) Resigned effective February 28, 1995.
(3) Elected Senior Vice President and Chief Financial Officer August 10, 1995; formerly Vice President.
(4) Elected Vice President effective January 6, 1995.
(5) Elected Vice President effective November 8, 1995.

Sch. 4

CORPORATE STRUCTURE

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	PacifiCorp Holdings, Inc.	Holding company	189,299,828	99.09%
3	Demand Side Receivable	Demand Side loan		
4		holder	1,735,631	0.91%
50	TOTAL		191,035,459	100%

THE ORGANIZATION

The Company is an electric utility that conducts a retail electric utility business through Pacific Power and Utah Power, and engages in power production and sales on a wholesale basis under the name PacifiCorp. The Company formed PacifiCorp Holdings in 1984 to hold the stock of the Company's principal subsidiaries and to facilitate the conduct of businesses not regulated as electric utilities. PacifiCorp's strategic business plan is to strengthen the scope and competitive position of its electric utility and telecommunications operations, to develop and expand its independent power production and cogeneration business, and to reduce the size and narrow the scope of its other diversified activities.

PacifiCorp has formed two subsidiaries to enable the company to compete for wholesale customers outside its existing service area. PacifiCorp Power Marketing Inc. (PPM) will actively market electric energy and related products and services throughout North America outside the western power grid. PacifiCorp Energy Inc. (PEI) will pursue opportunities related to coal mine operations and fuel procurement and management. PacifiCorp is entering the eastern power market through an agreement with Big Rivers Electric Corporation in western Kentucky.

In December of 1995 PacifiCorp entered the international markets with the purchase of Powercor, an electric distribution and marketing company in southeast Australia. Powercor serves 540,000 customers in suburban Melbourne and western and central portions of the State of Victoria.

Through PacifiCorp Holdings, the Company indirectly owns 100% of Pacific Telecom, a telecommunications company that provides voice, data, enhanced and other services through facilities associated with local exchange operations in 11 states. Pacific Telecom also owns, manages, or holds interests in cellular operations and properties, predominantly concentrated in the Midwest, and owns, operates and sells capacity on the North Pacific Cable (NPC), which connects the United States and Japan. In 1995 PacifiCorp Holdings purchased the 13% publicly held minority interest of Pacific Telecom. In 1995 Pacific Telecom completed the sale of Alascom, PTI's long distance operation in Alaska, to AT&T.

PacifiCorp Holdings owns 100% of Pacific Generation Corporation, which is engaged in the independent power production and cogeneration business. Holdings also owns 100% of PacifiCorp Financial Services (PFS). Consistent with PacifiCorp's strategic plan, PFS has sold substantial portions of its loan, leasing, manufacturing and real estate investments and expects to continue its disposition activities over the next several years. PFS presently expects to retain only its tax-advantaged investments in leveraged lease assets (primarily aircraft) and affordable housing projects.

The following pages provide an organization chart, in columnar form, of PacifiCorp subsidiaries. For each subsidiary, the percentage of ownership held by its parent company is listed as well as the state of incorporation. The listing of subsidiaries also contains a numerical reference for each subsidiary in the organization. This reference is attached to each affiliated interest entity throughout the report to facilitate cross-referencing.

LISTING OF PACIFICORP SUBSIDIARIES

SUBSIDIARIES OF THE COMPANY

PacifiCorp Holdings, Inc., a wholly-owned subsidiary of the Company and a Delaware corporation, has the following subsidiaries:

Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
PACE GROUP, Inc.	100%	Oregon
PacifiCorp Energy, Inc.	100%	Oregon
PacifiCorp Financial Services, Inc.	100%	Oregon
Pacific Harbor Capital, Inc.	100%	Delaware
PacifiCorp Capital, Inc.	100%	Virginia
PacifiCorp Credit, Inc.	100%	Oregon
Pacific Generation Company	100%	Oregon
Energy National, Inc.	100%	Utah
ONSITE Energy, Inc.	100%	Oregon
PacifiCorp Power Marketing, Inc.	100%	Oregon
PacifiCorp Telecom, Inc.	100%	Washington
PacifiCorp Trans, Inc.	100%	Oregon
PacifiCorp Australia, LLC	100%*	Oregon
PacifiCorp Australia Holdings Pty. Ltd.	100%	Australia
Powercor Australia Limited	100%	Australia

*Owned indirectly through two wholly owned subsidiaries of PacifiCorp Holdings, Inc.

Pacific Telecom, Inc., a 100% owned subsidiary of PacifiCorp Holding, Inc., and a Washington corporation, has the following subsidiaries:

Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
Cascade Autovon Company	100%	Washington
Eagle Telecommunications, Inc./Colorado	100%	Colorado
Eagle Valley Communications Corporation	100%	Colorado
Gem State Utilities Corporation	92%	Idaho
Indianhead Communications Corporation	100%	Wisconsin
Inter Island Telephone Company, Inc.	100%	Washington

International Communications Holdings, Inc.	100%	Delaware
North-West Cellular, Inc.	100%	Nevada

Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
Northland Telephone Company	100%	Minnesota
North-West Telephone Company	100%	Wisconsin
Northwestern Telephone Systems, Inc.	99%	Oregon
Pacific Telecom Cable, Inc.	80%	Delaware
Pacific Telecom Cellular, Inc.	100%	Delaware
Pacific Telecom Cellular of Alaska, Inc.	100%	Alaska
Pacific Telecom Cellular of 1-5, Inc.	100%	Washington
Pacific Telecom Cellular of Michigan, Inc.	100%	Michigan
Pacific Telecom Cellular of Oregon, Inc.	100%	Oregon
Pacific Telecom Cellular of South Dakota, Inc.	100%	South Dakota
Pacific Telecom Cellular of Washington, Inc.	100%	Washington
Pacific Telecom Cellular of Wisconsin, Inc.	100%	Wisconsin
Pacific Telecom Service Company	100%	Washington
Pacific Telecom Transmission Services, Inc.	100%	Oregon
Postville Telephone Company	100%	Wisconsin
Price County Telephone Cellular, Inc.	100%	Wisconsin
Rib Lake Cellular for Wisconsin RSA #2, Inc.	100%	Wisconsin
Telephone Utilities, Inc.	100%	Washington
Telephone Utilities of Alaska, Inc.	100%	Alaska
Telephone Utilities of Eastern Oregon, Inc.	100%	Oregon
Telephone Utilities of Northland, Inc.	100%	Alaska
Telephone Utilities of Oregon, Inc.	100%	Oregon
Telephone Utilities of Washington, Inc.	100%	Washington
Telephone Utilities of Wyoming, Inc.	100%	Wyoming
Wayside Telecom, Inc.	100%	Wisconsin
Wayside Cellular, Inc.	100%	Wisconsin
The Wayside Telephone Company	100%	Wisconsin

The Company also has the following subsidiaries:

Name of Subsidiary	Approximate Percentage of Voting Securities Owned	State or Jurisdiction of Incorporation or Organization
Centralia Mining Company	100%	Washington
Energy West Mining Company	100%	Utah
Glenrock Coal Company	100%	Wyoming
Interwest Mining Company	100%	Oregon
Pacific Minerals, Inc.	100%	Wyoming
Bridger Coal Company, a joint venture	66.67%	Wyoming
Williams Fork Company	19.7%	Colorado
Pyro Pacific Operating Company (owned by Pacific Mt. Poso Corp., a subsidiary of Pacific Generation Company)	7.5%	California

Sch. 5

CORPORATE ALLOCATIONS

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Corporate Management Fee		Three Factor Method			
2	$4,834,754	January - July	78.7% to Electric Utility Operations			
3	$6,217,311	August - December	83.4% to Electric Utility Operations			
4						
5	Electric Utility Portion					
6	$8,990,188			167,128	1.8590%	8,823,060
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34	TOTAL			167,128	1.8590%	8,823,060

Sch. 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	Pacific Telecom	Shareholder Service Records	Cost	220,034	0.03%	4,091
2		Telephone Svc & Pole Attach	Cost	168,250	0.03%	36,337
3						
4	PacifiCorp Financial Services	Leased Office Space	Cost	625,031	0.76%	11,607
5						
6	PacifiCorp Trans	Air Transportation	Cost	5,729,001	86.78%	111,678
7						
8	Centralia Mining	Coal & Mine Mgt	Cost	49,266,451	(a)	872,016
9						
10	Energy West	Coal & Mine Mgt	Cost	143,337,922	(a)	2,537,081
11						
12	Glenrock Coal	Coal & Mine Mgt	Cost	30,369,710	(a)	537,544
13						
14	Williams Fork	Coal & Mine Mgt	Cost	6,930,023	(a)	122,661
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27	(a) This company is not evaluated on a stand-alone basis. No balance sheet or income statement is available.					
28						
29						
30						
31						
32	TOTAL			236,646,422		4,233,015

Sch. 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	Pacific Telecom	Printing Service	Cost	2,478	0.0005%	0
2		Engineering Maps	Cost	22	0.0000%	0
3		Pole Contact Rental	Cost	120,099	0.0249%	0
4						
5	PacifiCorp Financial Services	Printing Service	Cost	771	0.0022%	0
6						
7	Pacific Generation	Printing Service	Cost	464	0.0047%	0
8		Consulting Service	Cost	192,206	1.9476%	0
9		Engineering Maps	Cost	85	0.0009%	0
10						
11	PacifiCorp Trans	Accounting Service	Cost	18,000	0.36%	0
12		Office Rent	Cost	2,846	0.06%	0
13		Printing Service	Cost	2,241	0.04%	0
14						
15	PacifiCorp Holdings, Inc.	Printing Service	Cost	216	0.0000%	0
16		Consulting Service	Cost	726,714	0.1351%	0
17						
18	PacifiCorp Energy, Inc	Printing Service	Cost	612	0.0923%	0
19		Consulting Service	Cost	50,258	7.5804%	0
20						
21	PacifiCorp Power Marketing, Inc.	Printing Service	Cost	248	0.0377%	0
22		Consulting Service	Cost	106,486	16.2079%	0
23						
24						
25						
26						
27						
28						
29	Note: Transactions involving services goods and services to affiliated companies are recorded in account 186, Miscellaneous Deferrred Debits.					
30	Billings to affiliates do not result in charges to accounts affecting ratepayers.					
31						
32	TOTAL			1,223,746		0

Sch. 8 MONTANA UTILITY INCOME STATEMENT

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	44,993,839	47,111,260	4.71%
2					
3		Operating Expenses			
4	401	Operation Expenses	22,562,033	23,444,610	3.91%
5	402	Maintenance Expenses	3,334,961	3,168,622	-4.99%
6	403	Depreciation Expenses	4,304,516	4,846,045	12.58%
7	404-405	Amortization of Electric Plant	246,042	357,189	45.17%
8	406	Amort. of Plant Acquisition Adjustments	99,241	104,038	4.83%
9	407	Amort. of Property Losses, Unrecovered Plant	48,282	38,181	-20.92%
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	1,583,405	1,669,507	5.44%
12	409.1	Income Taxes - Federal	1,685,251	2,309,576	37.05%
13		- Other	185,089	337,622	82.41%
14	410.1	Provision for Deferred Income Taxes	2,967,390	2,630,213	-11.36%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(1,443,960)	(1,475,666)	-2.20%
16	411.4	Investment Tax Credit Adjustment	0	0	
17	411.6	(Less) Gains from Disposition of Utility Plant	0	(11,915)	
18	411.7	Losses from Disposition of Utility Plant	0	0	
19	411.8	(Less) Gains from Sales of Emmission Allow.	0	(110,367)	
20		TOTAL Utility Operating Expenses	35,572,249	37,307,655	4.88%
21		NET UTILITY OPERATING INCOME	9,421,590	9,803,604	4.05%

Sch. 9 MONTANA REVENUES

	Account Number & Title		Last Year	This Year	% Change
22		Sales of Electricity			
23	440	Residential	15,893,729	16,852,868	6.03%
24	442	Commercial & Industrial - Small	10,921,864	11,580,152	6.03%
25		Commercial & Industrial - Large	7,741,853	9,216,688	19.05%
26	444	Public Street & Highway Lighting	140,393	145,920	3.94%
27	445	Other Sales to Public Authorities	0	0	
28	446	Sales to Railroads & Railways	0		
29	448	Interdepartmental Sales	7,708	0	-100.00%
30					
31		TOTAL Sales to Ultimate Consumers	34,705,547	37,795,628	8.90%
32	447	Sales for Resale	8,011,432	8,597,128	7.31%
33					
34		TOTAL Sales of Electricity	42,716,979	46,392,756	8.60%
35	449.1	(Less) Provision for Rate Refunds	0	0	
36					
37		TOTAL Revenue Net of Provision for Refunds	42,716,979	46,392,756	8.60%
38		Other Operating Revenues			
39	450	Forfeited Discounts & Late Payment Revenues	18,917	24,371	28.83%
40	451	Miscellaneous Service Revenues	8,721	(17,931)	-305.60%
41	453	Sales of Water & Water Power	1,790	0	-100.00%
42	454	Rent From Electric Property	174,153	336,781	93.38%
43	455	Interdepartmental Rents	0	0	
44	456	Other Electric Revenues	255,389	375,282	46.95%
45					
46		TOTAL Other Operating Revenues	458,970	718,504	56.55%
47		Total Electric Operating Revenues	43,175,949	47,111,260	9.11%

MONTANA OPERATION & MAINTENANCE EXPENSES

Account Number & Title		Last Year	This Year	% Change
Power Production Expenses				
Steam Power Generation				
Operation				
500	Operation Supervision & Engineering	226,351	255,564	12.91%
501	Fuel	8,497,767	8,383,122	-1.35%
502	Steam Expenses	421,553	452,068	7.24%
503	Steam from Other Sources	57,452	57,251	-0.35%
504	(Less) Steam Transferred - Cr.	0	0	
505	Electric Expenses	210,897	237,047	12.40%
506	Miscellaneous Steam Power Expenses	416,639	414,799	-0.44%
507	Rents	211	78	-63.08%
	TOTAL Operation - Steam	9,830,870	9,799,928	-0.31%
Maintenance				
510	Maintenance Supervision & Engineering	254,867	296,759	16.44%
511	Maintenance of Structures	128,411	127,586	-0.64%
512	Maintenance of Boiler Plant	864,557	837,638	-3.11%
513	Maintenance of Electric Plant	198,746	183,679	-7.58%
514	Maintenance of Miscellaneous Steam Plant	177,741	178,765	0.58%
	TOTAL Maintenance - Steam	1,624,322	1,624,427	0.01%
	TOTAL Steam Power Production Expenses	11,455,191	11,424,355	-0.27%
Nuclear Power Generation				
Operation				
517	Operation Supervision & Engineering	0	0	
518	Nuclear Fuel Expense	0	0	
519	Coolants & Water	0	0	
520	Steam Expenses	0	0	
521	Steam from Other Sources	0	0	
522	(Less) Steam Transferred - Cr.	0	0	
523	Electric Expenses	0	0	
524	Miscellaneous Nuclear Power Expenses	0	0	
525	Rents	0	0	
	TOTAL Operation - Nuclear	0	0	
Maintenance				
528	Maintenance Supervision & Engineering	0	0	
529	Maintenance of Structures	0	0	
530	Maintenance of Reactor Plant Equipment	0	0	
531	Maintenance of Electric Plant	0	0	
532	Maintenance of Miscellaneous Nuclear Plant	0	0	
	TOTAL Maintenance - Nuclear	0	0	
	TOTAL Nuclear Power Production Expenses	0	0	

MONTANA OPERATION & MAINTENANCE EXPENSES

Account Number & Title		Last Year	This Year	% Change
Power Production Expenses -continued				
Hydraulic Power Generation				
Operation				
535	Operation Supervision & Engineering	15,781	22,589	43.15%
536	Water for Power	802	1,053	31.33%
537	Hydraulic Expenses	71,753	66,003	-8.01%
538	Electric Expenses	67,028	76,929	14.77%
539	Miscellaneous Hydraulic Power Gen. Expenses	72,016	90,886	26.20%
540	Rents	224	59	-73.77%
	TOTAL Operation - Hydraulic	227,605	257,520	13.14%
Maintenance				
541	Maintenance Supervision & Engineering	6,411	11,100	73.14%
542	Maintenance of Structures	9,559	6,162	-35.53%
543	Maint. of Reservoirs, Dams & Waterways	25,815	29,464	14.14%
544	Maintenance of Electric Plant	69,906	58,528	-16.28%
545	Maintenance of Miscellaneous Hydro Plant	35,246	39,379	11.73%
	TOTAL Maintenance - Hydraulic	146,936	144,633	-1.57%
	TOTAL Hydraulic Power Production Expenses	374,541	402,153	7.37%
Other Power Generation				
Operation				
546	Operation Supervision & Engineering	251	322	28.05%
547	Fuel	28,548	43,083	50.91%
548	Generation Expenses	1,693	2,793	64.98%
549	Miscellaneous Other Power Gen. Expenses	787	1,311	66.55%
550	Rents	0	0	
	TOTAL Operation - Other	31,279	47,508	51.89%
Maintenance				
551	Maintenance Supervision & Engineering	251	320	27.80%
552	Maintenance of Structures	37	3	-91.01%
553	Maintenance of Generating & Electric Plant	537	366	-31.88%
554	Maintenance of Misc. Other Power Gen. Plant	461	412	-10.72%
	TOTAL Maintenance - Other	1,285	1,101	-14.35%
	TOTAL Other Power Production Expenses	32,564	48,609	49.27%
Other Power Supply Expenses				
555	Purchased Power	5,692,158	5,841,166	2.62%
556	System Control & Load Dispatching	107,176	124,090	15.78%
557	Other Expenses	125,639	119,913	-4.56%
	TOTAL Other Power Supply Expenses	5,924,973	6,085,169	2.70%
	TOTAL Power Production Expenses	17,787,269	17,960,287	0.97%

MONTANA OPERATION & MAINTENANCE EXPENSES

Line	Account Number & Title		Last Year	This Year	% Change
1		**Transmission Expenses**			
2	Operation				
3	560	Operation Supervision & Engineering	13,800	13,751	-0.35%
4	561	Load Dispatching	51,814	59,472	14.78%
5	562	Station Expenses	60,928	64,842	6.43%
6	563	Overhead Line Expenses	23,293	24,081	3.38%
7	564	Underground Line Expenses	21	2	-90.60%
8	565	Transmission of Electricity by Others	781,591	800,897	2.47%
9	566	Miscellaneous Transmission Expenses	9,802	16,533	68.68%
10	567	Rents	11,737	12,880	9.74%
11					
12		TOTAL Operation - Transmission	952,986	992,458	4.14%
13	Maintenance				
14	568	Maintenance Supervision & Engineering	7,666	12,477	62.75%
15	569	Maintenance of Structures	2,614	3,711	42.00%
16	570	Maintenance of Station Equipment	78,298	79,668	1.75%
17	571	Maintenance of Overhead Lines	45,854	57,841	26.14%
18	572	Maintenance of Underground Lines	414	15	-96.48%
19	573	Maintenance of Misc. Transmission Plant	11,574	2,690	-76.76%
20					
21		TOTAL Maintenance - Transmission	146,420	156,401	6.82%
22					
23		**TOTAL Transmission Expenses**	1,099,406	1,148,859	4.50%
24					
25		**Distribution Expenses**			
26	Operation				
27	580	Operation Supervision & Engineering	52,649	58,941	11.95%
28	581	Load Dispatching	49,166	45,645	-7.16%
29	582	Station Expenses	75,052	64,444	-14.13%
30	583	Overhead Line Expenses	347,624	216,565	-37.70%
31	584	Underground Line Expenses	220,710	172,629	-21.78%
32	585	Street Lighting & Signal System Expenses	22,018	23,199	5.36%
33	586	Meter Expenses	128,004	199,011	55.47%
34	587	Customer Installations Expenses	42,983	22,869	-46.80%
35	588	Miscellaneous Distribution Expenses	341,774	248,851	-27.19%
36	589	Rents	27,634	24,710	-10.58%
37					
38		TOTAL Operation - Distribution	1,307,613	1,076,863	-17.65%
39	Maintenance				
40	590	Maintenance Supervision & Engineering	59,745	86,510	44.80%
41	591	Maintenance of Structures	336	2,385	610.85%
42	592	Maintenance of Station Equipment	110,247	78,728	-28.59%
43	593	Maintenance of Overhead Lines	874,735	782,417	-10.55%
44	594	Maintenance of Underground Lines	170,329	91,337	-46.38%
45	595	Maintenance of Line Transformers	59,004	83,751	41.94%
46	596	Maintenance of Street Lighting, Signal Systems	12,096	14,190	17.31%
47	597	Maintenance of Meters	28,567	23,700	-17.04%
48	598	Maintenance of Miscellaneous Dist. Plant	19,261	17,791	-7.63%
49					
50		TOTAL Maintenance - Distribution	1,334,320	1,180,810	-11.50%
51					
52		**TOTAL Distribution Expenses**	2,641,933	2,257,673	-14.54%

MONTANA OPERATION & MAINTENANCE EXPENSES

Line		Account Number & Title	Last Year	This Year	% Change
1		**Customer Accounts Expenses**			
2	Operation				
3	901	Supervision	79,549	132,050	66.00%
4	902	Meter Reading Expenses	280,029	373,902	33.52%
5	903	Customer Records & Collection Expenses	674,932	756,758	12.12%
6	904	Uncollectible Accounts Expenses	64,801	107,530	65.94%
7	905	Miscellaneous Customer Accounts Expenses	16,288	24,103	47.99%
8					
9		**TOTAL Customer Accounts Expenses**	1,115,598	1,394,343	24.99%
10					
11		**Customer Service & Information Expenses**			
12	Operation				
13	907	Supervision	8,410	6,897	-17.99%
14	908	Customer Assistance Expenses	152,673	188,802	23.66%
15	909	Informational & Instructional Adv. Expenses	33,191	34,160	2.92%
16	910	Miscellaneous Customer Service & Info. Exp.	16,076	107,044	565.88%
17					
18		**TOTAL Customer Service & Info Expenses**	210,350	336,903	60.16%
19					
20		**Sales Expenses**			
21	Operation				
22	911	Supervision	6,504	23,036	254.17%
23	912	Demonstrating & Selling Expenses	245,855	191,960	-21.92%
24	913	Advertising Expenses	10,558	6,369	-39.67%
25	916	Miscellaneous Sales Expenses	48	71,549	****
26					
27		**TOTAL Sales Expenses**	262,964	292,915	11.39%
28					
29		**Administrative & General Expenses**			
30	Operation				
31	920	Administrative & General Salaries	1,446,355	1,597,284	10.44%
32	921	Office Supplies & Expenses	564,600	645,374	14.31%
33	922	(Less) Administrative Expenses Transferred - Cr.	0	0	
34	923	Outside Services Employed	152,679	131,683	-13.75%
35	924	Property Insurance	117,284	190,005	62.00%
36	925	Injuries & Damages	172,019	199,102	15.74%
37	926	Employee Pensions & Benefits	2,317,944	3,059,811	32.01%
38	927	Franchise Requirements	664	1,124	69.18%
39	928	Regulatory Commission Expenses	88,108	181,655	106.17%
40	929	(Less) Duplicate Charges - Cr.	(2,550,577)	(3,261,157)	-27.86%
41	930.1	General Advertising Expenses	21,139	2,000	-90.54%
42	930.2	Miscellaneous General Expenses	237,545	280,743	18.19%
43	931	Rents	130,034	133,378	2.57%
44					
45		**TOTAL Operation - Admin. & General**	2,697,795	3,161,001	17.17%
46	Maintenance				
47	935	Maintenance of General Plant	81,678	61,250	-25.01%
48					
49		**TOTAL Administrative & General Expenses**	2,779,473	3,222,251	15.93%
50					
51		**TOTAL Operation & Maintenance Expenses**	25,896,993	26,613,231	2.77%

Sch. 11	MONTANA TAXES OTHER THAN INCOME			
	Description of Tax	Last Year	This Year	% Change
1	**Property (Ad Valorem)**	1,470,496	1,433,072	-2.55%
2				
3	**Franchise and Occupation**	391	1,089	178.52%
4				
5	**Federal - Excise Superfund**	7,272	10,522	44.69%
6				
7	**Washington - Operating Revenue Fee**	111,109	116,162	4.55%
8				
9	**Washington - Pollution Control Credit**	(20,123)	(17,165)	14.70%
10				
11	**Montana - Energy Proceeds**	3,421	3,802	11.13%
12				
13	**Montana - Consumer Counsel**	10,453	29,119	178.57%
14				
15	**Utah Gross Receipts Tax**	0	92,578	
16				
17	**Other - Miscellaneous Taxes & License**	366	328	-10.38%
18				
19				
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48				
49				
50	TOTAL MT Taxes other than Income	1,583,385	1,669,507	5.44%

Sch. 12 **PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES**

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	General Electric Co.	Const./Maint. Contracts	3,522,247	65,479	1.8590%
2	Irwin Industries Inc.	Const./Maint. Contracts	3,573,761	66,436	1.8590%
3	Aspludh Tree Expert	Tree Trimming	4,108,899	76,384	1.8590%
4	Bonneville Power Administration	Const./Maint. Contracts	4,214,994	78,357	1.8590%
5	Hoffman Construction	Const./Maint. Contracts	4,505,862	83,764	1.8590%
6	Sturgeon Electric Co.	Const./Maint. Contracts	5,456,041	101,428	1.8590%
7	Ebcon, L.L.C.	Demand Side Program	6,800,556	126,422	1.8590%
8	Trees, Inc	Tree Trimming	7,039,724	130,868	1.8590%
9	Industrial Power Contractors, Inc.	Const./Maint. Contracts	8,444,541	156,984	1.8590%
10	Stoel Rives Boley Jones & Grey	Legal	9,643,708	179,277	1.8590%
11	James River Corp	Const./Maint. Contracts	13,978,286	259,856	1.8590%
12	International Line Builders, Inc.	Const./Maint. Contracts	15,420,389	286,665	1.8590%
13					
14					
15					
16					
17					
18					
19					
20					
21	Total		86,709,008	1,611,920	
22					
23					
24					
25					
26	Costs assignable directly to Montana:				
27	Bonneville Administration	Const./Maint. Contracts	121,404	121,404	
28	Bartlit, Beck, Herman, Palenchar &	Other Consultants	201,678	201,678	
29	Harp Line Constructors Co.	Const./Maint. Contracts	1,017,229	1,017,229	
30	Hayward Baker Inc.	Const./Maint. Contracts	341,960	341,960	
31	Squier Assoicates	Other Consultants	100,506	100,506	
32	Trees, Inc.	Tree Trimming	197,720	197,720	
33	Treweek Construction	Const./Maint. Contracts	153,585	153,585	
34	Triad Mechanical Inc	Const./Maint. Contracts	143,599	143,599	
35	W G Moe & Sons Inc	Const./Maint. Contracts	285,793	285,793	
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	**TOTAL Payments for Services**		2,563,473	2,563,473	

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana (1)	% Montana
1	Legislative Expense	519,169	0	0.00%
3	PacifiCorp D.C., Ltd.	220,013	0	0.00%
5	Westerberg & Associates - legislative legal fees	85,244	0	0.00%
7	Other Expenditures	245,420	0	0.00%
44	(1) PAC contributions are charged to account			
45	426.4 and are not allocated to Montana for			
46	rate making purposes.			
50	**TOTAL**	1,069,846	0	0.00%

Sch. 14 PENSION COSTS

	Description	Last Year	This Year	% Change
1				
2	Plan Name: PacifiCorp Retirement Plan			
3				
4	Defined Benefit Plan: yes			
5				
6	Defined Contribution Plan: yes			
7				
8	Is the Plan overfunded?: no			
9				
10	Actuarial Cost Method: Projected Unit Credit Method			
11				
12	IRS Code: 93-0246090			
13				
14	Annual Contribution by Employer: varies by year and			
15	funding status			
16				
17	Accumulated Benefit Obligation	778,405,326	871,588,826	11.97%
18	Projected Benefit Obligation	902,490,887	1,007,974,122	11.69%
19	Fair Value of Plan Assets	555,775,236	668,867,831	
20				
21	Discount Rate for Benefit Obligations	7.50%	7.25%	-3.33%
22	Expected Long-Term Return on Assets	8.75%	8.75%	0.00%
23				
24	Net Periodic Pension Cost:			
25	Service Cost	21,599,919	20,211,919	-6.43%
26	Interest Cost	63,328,316	68,369,468	7.96%
27	Return on Plan Assets	(37,572,734)	120,704,768	421.26%
28	Amortization of Transition Amount	7,076,156	9,968,828	40.88%
29	Amortization of Gains or Losses	0	0	
30	Total Net Periodic Pension Cost	54,431,657	219,254,983	302.81%
31				
32	Minimum Required Contribution	38,738,349	59,960,511	54.78%
33	Actual Contribution	42,185,514	78,613,355	86.35%
34	Maximum Amount Deductible	165,507,334	204,645,649	23.65%
35	Benefit Payments	55,092,259	56,178,388	1.97%
36				
37	Montana Intrastate Costs:			
38	Pension Costs	557,904	ERR	ERR
39	Pension Costs Capitalized	392,691	ERR	ERR
40	Accumulated Pension Asset (Liability) at Year End	(2,745,745)	(3,388,574)	-23.41%
41				
42	Number of Company Employees:			
43	Covered by the Plan	13,160	13,163	0.02%
44	Not Covered by the Plan	N/A	N/A	
45	Active	8,666	8,736	0.81%
46	Retired	3,662	3,641	-0.57%
47	Deferred Vested Terminated		786	

Sch. 15 OTHER POST EMPLOYMENT BENEFITS (OPEBS)

Line	Description	Last Year	This Year	% Chang
1	General Information			
2				
3	Assumptions:			
4	Discount Rate for Benefit Obligations	8.50%	8.50%	0.00%
5	Expected Long-Term Return on Assets	8.50%	8.75%	2.94%
6	Medical Cost Inflation Rate	11% to 5.5%	11% to 5.5%	
7	Actuarial Cost Method	Projected Unit	Projected Unit	
8		Credit Method	Credit Method	
9	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
10	Method - Tax Advantaged (Yes or No)			
11	VEBA - Yes			
12	401(h) - Yes			
13				
14				
15				
16	Describe Changes to the Benefit Plan:			
17				
18				
19				
20	Total Company			
21				
22	Accumulated Post Retirement Benefit Obligation (APBO)	312,661,915	314,570,203	0.61%
23	Fair Value of Plan Assets	60,265,083	60,265,083	0.00%
24	List the amount funded through each funding method:			
25	VEBA	23,860,664	21,626,559	-9.36%
26	401(h)	5,485,336	5,013,000	-8.61%
27	Other ____________			
28	Total amount funded	29,346,000	26,639,559	-9.22%
29				
30	List amount that was tax deductible for each type of funding:			
31	VEBA	23,860,664	21,626,559	-9.36%
32	401(h)	5,485,336	5,013,000	-8.61%
33	Other ____________			
34	Total amount that was tax deductible	29,346,000	26,639,559	-9.22%
35				
36	Net Periodic Post Retirement Benefit Cost:			
37	Service Cost	7,201,817	6,238,694	-13.37%
38	Interest Cost	24,817,284	26,660,978	7.43%
39	Return on Plan Assets	(3,248,918)	(6,193,898)	
40	Amortization of Transition Obligation	14,012,697	13,950,713	-0.44%
41	Amortization of Gains or Losses	0	0	
42	Total Net Periodic Post Retirement Benefit Cost	42,782,880	40,656,487	-4.97%
43				
44	Benefit Cost Expensed	25,109,272	28,581,510	13.83%
45	Benefit Cost Capitalized	17,673,608	12,074,977	-31.68%
46	Benefit Payments	13,325,000	55,092,260	313.45%
47				
48	Number of Company Employees:			
49	Covered by the Plan	12,507	12,325	-1.46%
50	Not Covered by the Plan	N/A	N/A	
51	Active	9,381	9,123	-2.75%
52	Retired	3,126	3,202	2.43%
53	Spouse/Dependants covered by the Plan	N/A	N/A	

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

	Description	Last Year	This Year	% Chang
1				
2	Montana			
3				
4	Accumulated Post Retirement Benefit Obligation (APBO)	5,460,328	5,847,860	7.10%
5	Fair Value of Plan Assets	1,052,469	1,120,328	6.45%
6	List the amount funded through each funding method:			
7	VEBA	416,703	402,038	-3.52%
8	401(h)	95,796	93,192	-2.72%
9	Other ____________			
10	Total amount funded	512,499	495,229	-3.37%
11				
12	List amount that was tax deductible for each type of funding:			
13	VEBA	416,703	402,038	-3.52%
14	401(h)	95,796	93,192	-2.72%
15	Other ____________			
16	Total amount that was tax deductible	512,499	495,229	-3.37%
17				
18	Net Periodic Post Retirement Benefit Cost:			
19	Service Cost	125,773	115,977	-7.79%
20	Interest Cost	433,409	495,628	14.36%
21	Return on Plan Assets	2,887	(115,145)	
22	Amortization of Transition Obligation	244,718	259,344	5.98%
23	Amortization of Gains or Losses	0	0	0.00%
24	Total Net Periodic Post Retirement Benefit Cost	806,786	755,804	-6.32%
25				
26	Benefit Cost Expensed	473,503	531,330	12.21%
27	Benefit Cost Capitalized	333,283	224,474	-32.65%
28	Benefit Payments	232,708	1,024,165	340.11%
29				
30	Number of Company Employees:			
31	Covered by the Plan	N/A	N/A	
32	Not Covered by the Plan	N/A	N/A	
33	Active	N/A	N/A	
34	Retired	N/A	N/A	
35	Spouse/Dependants covered by the Plan	N/A	N/A	
36				
37	Regulatory Treatment			
38				
39	Commission authorized - most recent			
40	Docket number: N/A			
41	Order number: N/A			
42				
43	Amount recovered through rates	N/A	N/A	

Sch. 16 TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Bekkedahl, Larry N	78,525	9,642	8,636	96,803	111,319	-13%
	Excess Life			486			
	Vehicle Allowance			8,100			
	Safety Award			50			
2	Redman, James M	73,956	3,753	9,528	87,237	84,910	3%
	Excess Life			1,203			
	Vehicle Allowance			8,100			
	Safety Award			225			
3	Jordan, Donald M	71,083	7,084	1,064	79,231	77,721	2%
	Excess Life			939			
	Safety Award			125			
4	Bech, Steven D.	52,654	2,322	18,757	73,733	69,738	6%
	Excess Life			1,305			
	Safety Award			125			
	OT/ Premium Pay			17,327			
5	Leuning, Clinton E.	51,910	2,489	19,313	73,712	73,972	-0%
	Excess Life			463			
	Safety Award			75			
	OT/ Premium Pay			18,775			
6	Gosney, Dennis L.	47,924	2,295	20,342	70,561	68,496	3%
	Excess Life			429			
	Safety Award			100			
	OT/ Premium Pay			19,813			
7	Hall, Daniel M.	49,620	2,266	17,947	69,833	66,607	5%
	Excess Life			666			
	Safety Award			45			
	OT/ Premium Pay			17,236			
8	Trebas Jr., William F.	47,537	2,333	18,915	68,785	69,516	-1%
	Excess Life			402			
	Safety Award			55			
	OT/ Premium Pay			18,458			
9	Coon, Larry G.	49,630	2,231	16,828	68,689	67,238	2%
	Excess Life			1,134			
	Safety Award			100			
	Relocation			15,594			
10	Hedges, Randy D.	47,429	2,247	18,480	68,156	64,415	6%
	Excess Life			277			
	Safety Award			45			
	OT/ Premium Pay			18,158			

Sch. 17 COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Frederick W. Buckman	570,002	88,500	297,164	955,666	1,692,273	-44%
	Restricted Stock Awards			288,946			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			718			
2	Charles E. Robinson	428,006	278,100	291,770	997,876	824,285	21%
	Restricted Stock Awards			282,938			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			1,332			
3	Verl R. Topham	280,000		111,666	391,666	381,256	3%
	Restricted Stock Awards			103,813			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			353			
4	Paul G. Lorenzini	249,000		83,502	332,502	339,973	-2%
	Restricted Stock Awards			75,688			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			314			
5	John A. Bohling	241,000		111,617	352,617	325,889	8%
	Restricted Stock Awards			103,813			
	Employee Stock Plan			7,500			
	Term Life Insurance Prem.			304			

		Account Title	Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	**Utility Plant**				
3	101	Electric Plant in Service	10,191,768,729	10,559,802,213	3.61%
4	101.1	Property Under Capital Leases	19,438,498	24,660,964	26.87%
5	102	Electric Plant Purchased or Sold			
6	103	Experimental Electric Plant Unclassified			
7	104	Electric Plant Leased to Others			
8	105	Electric Plant Held for Future Use	7,935,754	7,529,316	-5.12%
9	106	Completed Constr. Not Classified - Electric	44,033,469	36,755,712	-16.53%
10	107	Construction Work in Progress - Electric	310,923,840	306,180,306	-1.53%
11	108	(Less) Accumulated Depreciation	(3,168,920,628)	(3,399,411,578)	-7.27%
12	111	(Less) Accumulated Amortization	(77,016,562)	(95,450,413)	-23.93%
13	114	Electric Plant Acquisition Adjustments	144,067,770	138,194,702	-4.08%
14	115	(Less) Accum. Amort. Elec. Acq. Adj.			
15	118-11	Other Utility Plant - Net	1,857,204	1,936,827	4.29%
16	120	Nuclear Fuel (Net)			
17		**TOTAL Utility Plant**	7,474,088,074	7,580,198,049	1.42%
18					
19	**Other Property & Investments**				
20	121	Nonutility Property	7,395,067	6,322,584	-14.50%
21	122	(Less) Accum. Depr. & Amort. for Nonutil. Prop.	(1,181,174)	(821,148)	30.48%
22	123	Investments in Associated Companies	6,107,928	6,107,928	0.00%
23	123.1	Investments in Subsidiary Companies	902,586,532	1,352,846,625	49.89%
24	124	Other Investments	40,354,874	12,122,436	-69.96%
25	125	Sinking Funds			
26	128	Other Special Funds	3,798,468	4,041,138	6.39%
27		**TOTAL Other Property & Investments**	959,061,695	1,380,619,563	43.96%
28					
29	**Current & Accrued Assets**				
30	131	Cash	(15,460,055)	(27,443,470)	-77.51%
31	132-134	Special Deposits	3,767,991	18,600,000	393.63%
32	135	Working Funds	1,037,574	2,168,574	109.00%
33	136	Temporary Cash Investments			
34	141	Notes Receivable	917,313	43,815,119	4676.46%
35	142	Customer Accounts Receivable	207,901,130	221,351,262	6.47%
36	143	Other Accounts Receivable	27,551,433	32,389,096	17.56%
37	144	(Less) Accum. Provision for Uncollectible Accts.	(7,589,525)	(6,546,654)	13.74%
38	145	Notes Receivable - Associated Companies		3,446,633	
39	146	Accounts Receivable - Associated Companies	3,288,978	4,501,397	36.86%
40	151	Fuel Stock	52,999,196	62,683,966	18.27%
41	152	Fuel Stock Expenses Undistributed			
42	153	Residuals			
43	154	Plant Materials and Operating Supplies	114,453,892	117,108,828	2.32%
44	155	Merchandise	7,411		-100.00%
45	156	Other Material & Supplies			
46	157	Nuclear Materials Held for Sale			
47	163	Stores Expense Undistributed	4,600,823	5,849,084	27.13%
48	165	Prepayments	42,256,320	30,088,262	-28.80%
49	171	Interest & Dividends Receivable	1,296,605	1,486,028	14.61%
50	172	Rents Receivable	105,474	141,149	33.82%
51	173	Accrued Utility Revenues	96,590,892	89,852,585	-6.98%
52	174	Miscellaneous Current & Accrued Assets			
53		**TOTAL Current & Accrued Assets**	533,725,452	599,491,859	12.32%

BALANCE SHEET

		Account Title	Last Year	This Year	% Change
1					
2		**Assets and Other Debits (cont.)**			
3					
4		**Deferred Debits**			
5					
6	181	Unamortized Debt Expense	22,201,399	28,619,157	28.91%
7	182.1	Extraordinary Property Losses	1,771,001	706,613	-60.10%
8	182.2	Unrecovered Plant & Regulatory Study Costs	29,016,461	28,420,850	-2.05%
9	182.3	Regulatory Asset	1,047,511,665	1,028,354,099	-1.83%
10	183	Prelim. Survey & Investigation Charges	3,055,565	3,261,619	6.74%
11	184	Clearing Accounts			
12	185	Temporary Facilities	321,360	102,775	-68.02%
13	186	Miscellaneous Deferred Debits	55,413,828	151,332,869	173.10%
14	187	Deferred Losses from Disposition of Util. Plant			
15	188	Research, Devel. & Demonstration Expend.			
16	189	Unamortized Loss on Reacquired Debt	81,458,397	74,472,179	-8.58%
17	190	Accumulated Deferred Income Taxes	52,438,301	64,798,113	23.57%
18		**TOTAL Deferred Debits**	1,293,187,977	1,380,068,274	6.72%
19					
20		**TOTAL Assets & Other Debits**	10,260,063,198	10,940,377,745	6.63%

		Account Title	Last Year	This Year	% Change
21					
22		**Liabilities and Other Credits**			
23					
24		**Proprietary Capital**			
25					
26	201	Common Stock Issued	3,075,943,334	3,076,430,917	0.02%
27	202	Common Stock Subscribed			
28	204	Preferred Stock Issued	586,360,450	530,534,525	-9.52%
29	205	Preferred Stock Subscribed			
30	207	Premium on Capital Stock			
31	211	Miscellaneous Paid-In Capital			
32	212	Installments Received on Capital Stock	184,854	236,505	27.94%
33	213	(Less) Discount on Capital Stock			
34	214	(Less) Capital Stock Expense	(44,343,186)	(42,584,776)	3.97%
35	215	Appropriated Retained Earnings	3,193,230	3,253,538	1.89%
36	216	Unappropriated Retained Earnings	460,349,231	617,896,520	34.22%
37	217	(Less) Reacquired Capital Stock	(2,584,902)	(5,165,543)	-99.84%
38		**TOTAL Proprietary Capital**	4,079,103,011	4,180,601,686	2.49%
39					
40		**Long Term Debt**			
41					
42	221	Bonds	3,117,691,745	3,156,777,872	1.25%
43	222	(Less) Reacquired Bonds			
44	223	Advances from Associated Companies	59,574,922	41,063,554	-31.07%
45	224	Other Long Term Debt		175,825,925	
46	225	Unamortized Premium on Long Term Debt	10,483,277	8,495,975	-18.96%
47	226	(Less) Unamort. Discount on L-Term Debt-Dr.	(1,407,449)	(1,845,774)	-31.14%
48		**TOTAL Long Term Debt**	3,186,342,495	3,380,317,552	6.09%

BALANCE SHEET

		Account Title	Last Year	This Year	% Change
1					
2		**Total Liabilities and Other Credits (cont.)**			
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent	18,504,585	23,728,125	28.23%
7	228.1	Accumulated Provision for Property Insurance	4,157,951	3,777,119	-9.16%
8	228.2	Accumulated Provision for Injuries & Damages	6,927,190	7,098,496	2.47%
9	228.3	Accumulated Provision for Pensions & Benefits	157,223,121	190,944,689	21.45%
10	228.4	Accumulated Misc. Operating Provisions	15,259,417	15,193,956	-0.43%
11	229	Accumulated Provision for Rate Refunds			
12		**TOTAL Other Noncurrent Liabilities**	202,072,264	240,742,385	19.14%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable	433,047,241	681,894,000	57.46%
17	232	Accounts Payable	188,015,984	200,631,951	6.71%
18	233	Notes Payable to Associated Companies	33,404,523	1,918,085	-94.26%
19	234	Accounts Payable to Associated Companies	29,125,552	10,389,051	-64.33%
20	235	Customer Deposits	9,188,864	7,651,984	-16.73%
21	236	Taxes Accrued	41,811,027	99,205,072	137.27%
22	237	Interest Accrued	63,280,205	66,257,592	4.71%
23	238	Dividends Declared	86,772,099	85,640,802	-1.30%
24	239	Matured Long Term Debt	3,647,400		-100.00%
25	240	Matured Interest	98,591		-100.00%
26	241	Tax Collections Payable	11,008,092	12,922,638	17.39%
27	242	Miscellaneous Current & Accrued Liabilities	36,600,997	36,542,753	-0.16%
28	243	Obligations Under Capital Leases - Current	933,913	932,839	-0.12%
29		**TOTAL Current & Accrued Liabilities**	936,934,488	1,203,986,767	28.50%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	12,419,523	13,183,732	6.15%
34	253	Other Deferred Credits	76,079,825	144,200,211	89.54%
35	254	Regulatory Liabilities	76,536,699	60,803,020	-20.56%
36	255	Accumulated Deferred Investment Tax Credit	174,311,459	150,256,339	-13.80%
37	256	Deferred Gains from Disposition Of Util. Plant			
38	257	Unamortized Gain on Reacquired Debt	3,291,126	2,695,697	-18.09%
39	281-283	Accumulated Deferred Income Taxes	1,512,972,308	1,563,590,356	3.35%
40		**TOTAL Deferred Credits**	1,855,610,940	1,934,729,355	4.26%
41					
42		**TOTAL Liabilities & Other Credits**	10,260,063,198	10,940,377,745	6.63%

Name of Respondent PacifiCorp	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1995

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.

2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility.Give also a brief explanation of any dividends in arrears on cumulative preferred stock.

3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.

4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.

5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.

6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be attached hereto.

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SEE PAGE 123 FOR REQUIRED INFORMATION

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PacifiCorp (the "Company") is an integrated electric utility that conducts its retail electric utility operations through Pacific Power and Utah Power, and engages in power production and sales on a wholesale basis under the name PacifiCorp. The Company is the indirect owner, through its wholly owned subsidiary, PacifiCorp Holdings, Inc. ("Holdings"), of wholly owned subsidiaries including a telecommunications company (Pacific Telecom, Inc.), formerly 87 percent owned, see Note 13, an Australian electricity distributor, (Powercor Australia Limited) acquired on December 12, 1995, see Note 13, and a financial services company (PacifiCorp Financial Services, Inc.).

These regulatory basis financial statements have been prepared for the purpose of complying with, and on the basis of accounting practices specified by the Federal Energy Regulatory Commission ("FERC"). Accordingly, investments in subsidiaries are accounted for and reported on the equity basis of accounting and these regulatory basis financial statements do not include debt of the Leveraged ESOP Trust established under the PacifiCorp K Plus Employee Savings and Stock Ownership Plan ("K Plus Plan") which is guaranteed by Holdings and do not present financial position, results of operations and changes in cash flows in accordance with generally accepted accounting principles, which would require that the accounts of the subsidiaries be consolidated with those of PacifiCorp.

Holdings guarantees certain debt of the Leveraged ESOP Trust established under the K Plus Plan (the "Trust"). The amount guaranteed at December 31, 1995 was $12,240,000. The debt was used to acquire the Company's common stock. Remaining unallocated common shares held in trust totaled 559,543 at December 31, 1995.

Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1995

NOTES TO FINANCIAL STATEMENTS (Continued)

The following schedule shows increases and decreases had the accounts of the subsidiaries been consolidated with those of the Company:

THOUSANDS OF DOLLARS	CONSOLIDATED	FERC FORM 1 FINANCIALS	INCREASE/ (DECREASE)
AT DECEMBER 31, 1995			
Net property, plant and equipment	$9,952,296	$7,580,198	$2,372,098
Current assets	912,224	599,492	312,732
Investments in subsidiaries	-	1,352,847	(1,352,847)
Other assets	3,150,686	1,407,841	1,742,845
Common stock	3,012,927	3,028,917	(15,990)
Retained earnings	632,420	621,150	11,270
Guaranty of Employee Stock Ownership Plan borrowings	(12,240)	-	(12,240)
Preferred stock	530,535	530,535	-
Long-term debt and capital lease obligations	4,968,175	3,621,060	1,347,115
Current liabilities	2,004,917	1,203,987	800,930
Deferred credits	2,855,468	1,934,729	920,739
Minority interest	23,004	-	23,004
AT DECEMBER 31, 1994			
Net property, plant and equipment	$8,446,215	$7,474,088	$ 972,127
Current assets	815,427	533,725	281,702
Investments in subsidiaries	-	902,587	(902,587)
Other assets	2,583,984	1,349,663	1,234,321
Common stock	3,010,629	3,029,200	(18,571)
Retained earnings	474,273	463,543	10,730
Guaranty of Employee Stock Ownership Plan borrowings	(25,126)	-	(25,126)
Preferred stock	586,360	586,360	-
Long-term debt and capital lease obligations	3,768,192	3,388,415	379,777
Current liabilities	1,269,089	936,934	332,155
Deferred credits	2,654,296	1,855,611	798,685
Minority interest	107,913	-	107,913

NOTES TO FINANCIAL STATEMENTS (Continued)

THOUSANDS OF DOLLARS	CONSOLIDATED	FERC FORM 1 FINANCIALS	INCREASE/ (DECREASE)
FOR THE YEAR ENDED DECEMBER 31, 1995			
Operating revenues	$ 3,400,913	$ 2,616,914	$ 783,999
Operating expenses	2,353,120	2,023,053	330,067
Net cash provided by oper. activities	911,953	671,022	240,931
Net cash used in investing activities	(2,332,920)	(662,723)	(1,670,197)
Net cash provided by (used in) financing activities	1,419,838	(4,319,532)	5,739,370
FOR THE YEAR ENDED DECEMBER 31, 1994			
Operating revenues	$3,506,531	$2,648,704	$ 857,827
Operating expenses	2,484,206	2,042,821	441,385
Net cash provided by oper. activities	962,073	751,761	210,312
Net cash used in investing activities	(340,053)	(563,383)	223,330
Net cash used in financing activities	(629,942)	(159,987)	(469,955)

se of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Regulation

Accounting for the Company conforms with generally accepted accounting principles as applied to regulated public utilities and as prescribed by the Federal Energy Regulatory Commission and the regulatory commissions of the various states in which the Company operates.

Accounting for the Effects of Regulation

The Company prepares its financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") 71, "Accounting for the Effects of Certain Types of Regulation." Accounting under SFAS 71 is appropriate as long as: rates are established by or subject to approval by independent, third-party regulators; rates are designed to recover the specific enterprise's cost-of-service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. In applying SFAS 71, the Company must give consideration to changes in the level of demand

Name of Respondent PacifiCorp	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1995

NOTES TO FINANCIAL STATEMENTS (Continued)

or competition during the cost recovery period. In accordance with SFAS 71, the Company capitalizes certain costs in accordance with regulatory authority, whereby those costs will be expensed and recovered in future periods.

Regulatory assets-net at December 31, 1995 and 1994 included the following:

THOUSANDS OF DOLLARS	1995	1994
Deferred taxes - net	$ 695,312	$ 713,094
Deferred pension costs	116,772	148,300
Demand-side resource costs	109,972	84,569
Unamortized net losses on reacquired debt	71,776	78,167
Unrecovered Trojan Plant and regulatory study costs	28,421	29,016
Various other costs	46,202	34,029
TOTAL	$1,068,455	$1,087,175

If the Company, at some point in the future, determines that all or a portion of the operations no longer meet the criteria for continued application of SFAS 71, the Company would be required to adopt the provisions of SFAS 101, "Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71." Adoption of SFAS 101 would require the Company to write off the regulatory assets and liabilities relating to those operations not meeting SFAS 71 requirements.

Cash Flow Information

For the purposes of these financial statements, the Company considers all liquid investments with original maturities of three months or less to be cash equivalents.

Supplemental information required by SFAS 95, "Statement of Cash Flows," for the years 1995 and 1994 is as follows:

THOUSANDS OF DOLLARS	1995	1994
Cash paid during the year for:		
Interest (net of amount capitalized)	$254,012	$258,386
Income taxes	122,426	125,686
Noncash financing activities:		
8.55% Junior subordinated debentures exchanged for 2,233,037 shares of $1.98 no par serial preferred stock	55,826	-

Property, Plant and Equipment

Property, plant and equipment is stated at original cost of contracted services, direct labor and material, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable utility properties retired, including the cost of removal, less salvage, is charged to accumulated depreciation.

Depreciation and Amortization

At December 31, 1995, the average depreciable life of property, plant and equipment by category was: Production, 42 years; Transmission, 49 years; Distribution, 34 years and Other, 15 years.

Depreciation and amortization is computed generally by the straight-line method over the estimated useful lives of the related assets. Provisions for depreciation (excluding amortization of capital leases) were 3.0 percent of average depreciable assets in 1995 and 1994.

Inventory Valuation

Inventories are generally valued at the lower of average cost or market.

Derivatives

Gains and losses on hedges of existing assets and liabilities are included in the carrying amounts of those assets or liabilities and are recognized in income as part of those carrying amounts.

Interest Capitalized

Costs of debt and equity funds applicable to utility properties are capitalized during construction. Generally, the composite capitalization rates allowed were 6.15 percent for 1995 and 4.7 percent for 1994.

Income Taxes

The Company uses the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax bases of assets and liabilities and their financial reporting amounts.

Investment tax credits are deferred and amortized to income over the average estimated lives of the related properties.

Revenue Recognition

The Company accrues estimated unbilled revenues for electric services provided after cycle billing to month-end.

Reclassification

Certain amounts from the prior year have been reclassified to conform with the 1995 method of presentation. These reclassifications had no effect on previously reported net income.

New Accounting Standard

Effective January 1, 1996, the Company adopted SFAS 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." This Statement requires that long-lived assets and certain identifiable intangibles to be held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The Company does not expect the adoption of this standard in 1996 to have a material effect on its regulatory basis financial statements.

NOTE 2. SHORT-TERM DEBT AND BORROWING ARRANGEMENTS

Information concerning short-term debt and borrowing arrangements is as follows:

THOUSANDS OF DOLLARS	DECEMBER 31 BALANCE	DECEMBER 31 AVERAGE INTEREST RATE (a)	FOR THE YEAR AVERAGE OUTSTANDING	FOR THE YEAR AVERAGE INTEREST RATE (b)
1995	$681,894	5.9%	$407,210	5.9%
1994	$433,047	6.0%	$372,804	4.5%

(a) Computed by dividing the total interest on principal amounts outstanding at the end of the period by the weighted daily principal amounts outstanding.

(b) Computed by dividing the total interest expense for the period by the average daily principal amount outstanding for the period.

At December 31, 1995, the Company's commercial paper and bank line borrowings were supported by a $500 million revolving credit agreement.

Commitment fees were approximately $555,000 in 1995 and $717,000 in 1994.

NOTE 3. COMMON AND PREFERRED STOCK

THOUSANDS OF SHARES/DOLLARS	SHARES COMMON STOCK	SHARES PREFERRED STOCK	COMMON SHARE-HOLDERS' CAPITAL
At January 1, 1994	281,021	10,532	$2,974,406
Sales through Dividend Reinvestment and Stock Purchase Plan	2,194		37,997
Sales through Employees' Stock Plans	1,036		17,909
Stock expense, redemptions and repurchases			(1,112)
At December 31, 1994	284,251	10,532	3,029,200
Sales through Employees' Stock Plans	26		487
Dividend Reinvestment Plan			(43)
Junior subordinated debentures exchanged for preferred stock		(2,233)	1,854
Stock expense, redemptions and repurchases			(2,581)
At December 31, 1995	284,277	8,299	$3,028,917

At December 31, 1995, there were 8,378,511 authorized but unissued shares of common stock reserved for issuance under the Dividend Reinvestment and Stock Purchase Plan and the Employee Savings and Stock Ownership Plans and for sales to the public. Eligible employees under the employee plans may direct their pretax elective contributions into the purchase of the Company's common stock. The Company makes matching contributions, equal to a percentage of employee contributions, which are invested in the Company's common stock. Employee contributions eligible for matching contributions are limited to 6 percent of compensation.

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon involuntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends.

Name of Respondent PacifiCorp	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr)	Year of Report Dec. 31, 1995

NOTES TO FINANCIAL STATEMENTS (Continued)

PREFERRED STOCK OUTSTANDING
THOUSANDS OF SHARES/DOLLARS

DECEMBER 31 Series	1995 SHARES	1995 AMOUNT	1994 SHARES	1994 AMOUNT
SUBJECT TO MANDATORY REDEMPTION				
No Par Serial Preferred, 16,000 Shares Authorized				
$7.12 ($100 stated value)	440	$44,000	440	$44,000
7.70	1,000	100,000	1,000	100,000
7.48	750	75,000	750	75,000
TOTAL		$219,000		$219,000
NOT SUBJECT TO MANDATORY REDEMPTION				
$1.16 ($25 stated value)	193	4,828	193	4,828
1.18	420	10,503	420	10,503
1.28	381	9,530	381	9,530
1.76	394	9,847	394	9,847
1.98	502	12,550	502	12,550
2.13	666	16,655	666	16,655
1.98, Series 1992	2,767	69,175	5,000	125,000
Auction Rate ($100,000 stated value) (a)	1	100,000	1	100,000
Serial Preferred $100 Stated Value Per Share, 3,500 Shares Authorized				
4.52%	2	207	2	207
4.56	85	8,459	85	8,459
4.72	70	6,989	70	6,989
5.00	42	4,200	42	4,200
5.40	66	6,596	66	6,596
6.00	6	593	6	593
7.00	18	1,806	18	1,806
7.96	135	13,518	135	13,518
8.92	69	6,937	69	6,937
9.08	165	16,489	165	16,489
5% Preferred, $100 Stated Value, 127 Shares Authorized and Outstanding	127	12,653	127	12,653
TOTAL		$311,535		$367,360

(a) Dividend rates at December 31, 1995 on 500 shares each of Series A and Series C were 4.7 percent and 4.6 percent, respectively.

Mandatory redemption requirements at stated value plus accrued dividends on No Par Serial Preferred Stock are as follows: beginning in 1997, 15,000 shares of the $7.12 series are redeemable annually; the $7.70 series is redeemable in its entirety on August 15, 2001; and 37,500 shares of the $7.48 series are redeemable on each June 15 from 2002 through 2006, with all shares outstanding on June 15, 2007 redeemable on that date. Mandatory redemption requirements for 1993 through 1996 on the $7.12 series were satisfied by the purchase of 60,000 shares at a discount in December 1992. If the Company is in default in its obligation to make any future redemptions on the $7.12 series or the $7.48 series, it may not pay cash dividends on common stock.

NOTE 4. LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

The Company's long-term debt and capital lease obligations at December 31 were as follows:

THOUSANDS OF DOLLARS	1995	1994
First mortgage and collateral trust bonds		
Maturing 1996 through 2000/4.5%-9.5% (a)	$987,550	$1,038,218
Maturing 2001 through 2005/6%-10%	644,335	689,535
Maturing 2006 through 2010/6.6%-8.3%	157,559	59,002
Maturing 2011 through 2015/7.3%-9.2%	238,074	240,379
Maturing 2016 through 2020/8.5%-8.6%	35,879	36,463
Maturing 2021 through 2024/6.7%-8.6%	361,500	361,500
Guaranty of pollution control revenue bonds		
5.6%-5.7% due 2021 through 2023 (b)	71,200	71,200
Variable rate due 2013 through 2024 (b)(c)	216,470	216,470
Variable rate due 2005 through 2025 (c)	456,625	404,925
Funds held by trustees	(12,414)	-
8.4%-8.6% Junior subordinated debentures due 2025 through 2035	175,826	-
Advances from Associated Companies	41,064	59,575
Unamortized premium and discount	6,650	9,075
Capital lease obligations	24,661	19,439
Total	3,404,979	3,205,781
Less current maturities	176,802	45,080
TOTAL	$3,228,177	$3,160,701

(a) Includes $50 million of 9.4 percent bonds issued to secure obligations under an equivalent 10-year yen loan. A currency swap converted the fixed rate yen liability to a floating rate U.S. dollar liability based on six-month LIBOR plus .02 percent (interest rate 6.8 percent at December 31, 1995).

(b) Secured by pledged first mortgage and collateral trust bonds generally at the same interest rates, maturity dates and redemption provisions as the secured pollution control revenue bonds.

(c) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

Approximately $4.6 billion of the assets of the Company secure long-term debt and capital lease obligations. First mortgage and collateral trust bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures.

The junior subordinated debentures are unsecured obligations of the Company and are subordinated to the Company's first mortgage bonds, pollution control revenue bonds, commercial paper, capital lease obligations and any future senior indebtedness.

The annual maturities of long-term debt, capital lease obligations and redeemable preferred stock outstanding are $176,802,000, $205,573,000, $196,603,000, $299,313,000 and $170,167,000 in 1996 through 2000, respectively.

NOTE 5. DERIVATIVES

The Company seeks to reduce net income and cash flow exposure to changing interest and currency exchange rates and commodity price risks through the use of derivative financial instruments. The Company's participation in derivative transactions involves instruments that have a close correlation with its portfolio of liabilities, thereby managing its risk. Derivatives have been designed for hedging purposes and not held or issued for speculative purposes.

Notional Amounts and Credit Exposure of Derivatives--The notional amounts of derivatives summarized below do not represent amounts exchanged and, therefore, are not a measure of the exposure of the Company through its use of derivatives. The amounts exchanged are calculated on the basis of the notional amounts and other terms of the derivatives, which relate to interest and exchange rates.

The Company is exposed to credit-related losses in the event of nonperformance by counterparties to financial instruments, but it does not expect any counterparties to fail to meet their obligations given their high credit ratings. The Company's credit policy provides that counterparties satisfy minimum credit ratings. The credit exposure of interest rate and foreign exchange contracts is represented by the fair value of contracts with a positive fair value at the reporting date.

The Company enters into interest rate swaps in managing its interest rate risk. At December 31, 1995, the Company had four outstanding interest rate contracts with commercial banks and Fortune 500 companies, having a total notional amount of $150 million. These agreements effectively change the Company's interest rate exposure on the underlying variable rate debt to rates of 6.9 percent to 8.9 percent. These contracts mature at various times through the year 2000. A currency swap has been used to convert a 7.4 billion yen liability to a floating rate $50 million U.S. dollar liability based on the six-month London Interbank Offered Rate plus .02 percent.

The Company uses interest rate swaps to adjust the characteristics of its liability portfolio by hedging portions of its interest expense, allowing the Company to establish a mix of fixed or variable interest rates on its outstanding debt.

NOTE 6. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying value of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments.

The fair value of redeemable preferred stock, based upon bid prices from an investment bank, is estimated to be $240 million, or 110 percent of the carrying value of $219 million at December 31, 1995 and $219 million, or 100 percent of the carrying value at December 31, 1994.

The fair value of long-term debt has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities. Current maturities of long-term debt were included and the leveraged ESOP loan guaranty and capital lease obligations were excluded. The fair value of the Company's long-term debt is estimated to be $3.6 billion, or 106 percent of the carrying value of $3.4 billion, and $3.1 billion, or 96 percent of the carrying value of $3.2 billion, at December 31, 1995 and 1994, respectively.

The fair value of interest rate and currency swaps is the estimated amount the Company would pay to terminate the agreements, taking into account current interest and currency exchange rates and the current creditworthiness of the swap counterparties. The estimated termination cost would have been $33 million and $29 million at December 31, 1995 and 1994, respectively.

NOTE 7. LEASES

The Company leases certain properties under leases with various expiration dates and renewal options. Rentals on lease renewals are subject to negotiation. Certain leases provide for options to purchase at fair market value. The Company is also committed to pay all taxes, expenses of operation (other than depreciation) and maintenance applicable to the leased property.

Net rent expense for the years ending December 31, 1995 and 1994 was $12,368,000 and $14,867,000, respectively.

Future minimum lease payments under noncancellable operating leases are $1,900,000, $1,061,000, $1,151,000, $1,132,000 and $1,298,000 for 1996 through 2000, respectively.

NOTE 8. COMMITMENTS AND CONTINGENCIES

Construction and Other

Construction and acquisitions are estimated at $691 million for 1996. As part of these programs, substantial commitments have been made.

Several Superfund sites have been identified where the Company has been or may be designated as a potentially responsible party. Future costs associated with the disposition of these matters are not expected to be material to the Company's regulatory basis financial statements.

The Company is party to various legal claims, actions and complaints, certain of which involve material amounts. Although the Company is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, management currently believes that disposition of these matters will not have a materially adverse effect on the Company's regulatory basis financial statements.

Jointly Owned Plants

At December 31, 1995, the Company's participation in jointly owned plants was as follows:

THOUSANDS OF DOLLARS	THE COMPANY'S SHARE	PLANT IN SERVICE	ACCUMULATED DEPRECIATION	CONSTRUCTION WORK IN PROGRESS
Centralia	47.5%	$177,845	$104,227	$3,953
Jim Bridger Units 1,2,3 and 4	66.7%	782,462	299,662	5,001
Trojan(a)	2.5%			
Colstrip Units 3 and 4	10.0%	201,840	58,017	1,786
Hunter Unit 1	93.8%	259,091	94,130	1,302
Hunter Unit 2	60.3%	186,914	62,145	1,000
Wyodak	80.0%	303,051	88,469	1,002
Craig Station Units 1 and 2	19.3%	146,973(b)	53,786	3,247
Hayden Station Unit 1	24.5%	16,918(b)	11,824	197
Hayden Station Unit 2	12.6%	16,918(b)	8,579	267

(a) Plant, inventory, fuel and decommissioning costs totaling $28 million relating to the Trojan Plant were included in regulatory assets-net at December 31, 1995. Recovery of these costs is pending approval of certain regulatory commissions.

(b) Excludes unallocated acquisition adjustments of $123.9 million.

Under the joint agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. The Company's portion is recorded in its applicable operations, maintenance and tax accounts.

Substantial amounts of power are purchased from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project annual costs (operating expenses and debt service). These costs are included in operations expense. The Company is required to pay its portion of the debt service, whether or not any power is produced. The arrangements provide for nonwithdrawable power and the majority also provide for additional power, withdrawable by the districts upon one to five years' notice. For 1995, such purchases approximated 3.4 percent of energy requirements; an additional 14 percent was obtained through other purchase and net interchange arrangements.

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Name of Respondent PacifiCorp	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1995

NOTES TO FINANCIAL STATEMENTS (Continued)

At December 31, 1995, the Company's share of long-term arrangements with public utility districts was as follows:

THOUSANDS OF DOLLARS

GENERATING FACILITY	YEAR CONTRACT EXPIRES	CAPACITY (kW)	PERCENTAGE OF OUTPUT	ANNUAL COSTS (a)
Wanapum	2009	155,444	18.7%	$ 5,003
Priest Rapids	2005	109,602	13.9	4,023
Rocky Reach	2011	64,297	5.3	2,099
Wells	2018	59,617	7.7	1,958
TOTAL		388,960		$13,083

(a) Annual costs include debt service of $7.9 million.

The Company has a 4 percent interest in the Intermountain Power Project ("Project"), located in central Utah. The Company and the City of Los Angeles have agreed that the City will purchase capacity and energy from Company plants equal to the Company's 4 percent entitlement of the Project at a price equivalent to 4 percent of the expenses and debt service of the Project.

NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 9. INCOME TAXES

Excluding equity in subsidiaries' earnings or losses, the Company's effective combined federal and state income tax rate was 40 percent and 37 percent in 1995 and 1994, respectively. The difference between taxes calculated as if the statutory federal tax rate of 35 percent in 1995 and 1994 was applied to income before income taxes and the recorded tax expense is reconciled as follows:

THOUSANDS OF DOLLARS	1995	1994
COMPUTED FEDERAL INCOME TAXES	$184,237	$209,804
REDUCTION (INCREASE) IN TAX RESULTING FROM		
Depreciation differences (flow-through basis)	(9,679)	(8,357)
Investment tax credits	8,927	7,913
Depletion	1,600	4,119
Audit settlement	(14,535)	
Other items capitalized and miscellaneous differences	627	(226)
Total	(13,060)	3,449
FEDERAL INCOME TAX	197,297	206,355
STATE INCOME TAX, NET OF FEDERAL INCOME TAX BENEFIT	15,662	13,816
TOTAL INCOME TAX EXPENSE	$212,959	$220,171

The provision for income taxes is summarized as follows:

	1995	1994
CURRENT		
Federal	$166,722	$132,780
State	19,252	15,693
Total	185,974	148,473
DEFERRED		
Federal	31,067	74,049
State	4,845	5,562
Total	35,912	79,611
INVESTMENT TAX CREDITS	(8,927)	(7,913)
TOTAL INCOME TAX EXPENSE	$212,959	$220,171

The tax effects of significant items comprising the Company's net deferred tax liability at December 31 are as follows:

THOUSANDS OF DOLLARS	1995	1994
DEFERRED TAX LIABILITIES		
Property, plant and equipment	$ 796,352	$ 736,429
Regulatory asset	756,115	789,630
Other deferred liabilities	14,721	18,001
DEFERRED TAX ASSETS		
Regulatory liability	(60,803)	(76,537)
Book reserves not deductible for tax	(7,593)	(6,989)
NET DEFERRED TAX LIABILITY	$1,498,792	$1,460,534

During 1995, the Company and the Internal Revenue Service (the "IRS") agreed on a settlement of all issues related to the IRS examination of the Company's federal income tax returns for the years 1983 through 1988, including matters relating to the Company's abandonment of its 10 percent interest in Washington Public Power Supply System Unit No. 3.

The Company's 1989 and 1990 federal income tax returns are currently under examination by the IRS.

NOTE 10. RETIREMENT PLANS

The Company has a pension plan covering substantially all of its employees. Benefits under this plan are generally based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from Social Security. Pension costs are funded annually by no more than the maximum amount of pension expense which can be deducted for federal income tax purposes. Unfunded prior service costs are amortized over the remaining service period of employees expected to receive benefits. At December 31, 1995, plan assets were primarily invested in common stocks, bonds and U.S. government obligations.

NOTES TO FINANCIAL STATEMENTS (Continued)

Net pension cost for the years ended December 31 is summarized as follows:

THOUSANDS OF DOLLARS	1995	1994
Service cost - benefits earned	$ 20,476	$ 21,894
Interest cost on projected benefit obligation	69,125	63,999
Actual (gain) loss on plan assets	(120,705)	3,214
Net amortization and deferral	81,523	(43,625)
Regulatory deferral (a)	29,446	700
NET PENSION COST	$ 79,865	$46,182

(a) The Company has received accounting orders from its primary and certain other regulatory authorities to defer the difference between pension cost as determined in accordance with SFAS 87 and 88 and that determined for funding purposes. See "Accounting for the Effects of Regulation" in Note 1.

The funded status, net pension liability and significant assumptions at December 31 are as follows:

THOUSANDS OF DOLLARS	1995	1994
Actuarial present value of benefit obligations		
Vested benefit obligation	$ 827,031	$ 666,577
Accumulated benefit obligation	$ 880,993	$ 706,771
Projected benefit obligation	$1,018,821	$ 810,104
Plan assets at fair value	668,868	541,377
Projected benefit obligation in excess of plan assets	(349,953)	(268,727)
Unrecognized prior service cost	11,822	8,793
Unrecognized net loss	97,174	4,154
Unrecognized net obligation at January 1, being amortized over 3 to 15 years	94,011	101,073
Minimum liability adjustment	(65,179)	(11,635)
NET PENSION LIABILITY	$ (212,125)	$(166,342)
Discount rate	7.25%	8.5%
Expected long-term rate of return on assets	8.75%	8.75%
Rate of increase in compensation levels	5-5.5%	5-5.5%

The Company offered early retirement incentive programs in 1987 and 1990. Included in the table above is the present value of all future termination benefits provided of $61 million. The Company received regulatory accounting orders to defer early retirement costs as a regulatory asset to be amortized through the year 2020. See "Accounting for the Effects of Regulation" in Note 1.

NOTE 11. OTHER POSTRETIREMENT BENEFITS

The Company provides health care and life insurance benefits for eligible retirees on a basis substantially similar to those who are active employees. The cost of postretirement benefits are accrued over the active service period of employees. The Company funds postretirement benefit expense on a pay-as-you-go basis for those employees retired prior to January 1, 1994. The Company funds postretirement benefit expense through a combination of funding vehicles for those employees retiring after January 1, 1994. The Company funded $26,640,000 and $29,346,000 of postretirement benefit expense during 1995 and 1994, respectively. These funds are invested in common stock, bonds and U.S. Government obligations.

The net periodic postretirement benefit cost for the years ended December 31, 1995 and 1994 are summarized as follows:

THOUSANDS OF DOLLARS	1995	1994
Service costs - benefits earned	$ 6,239	$ 7,202
Interest cost on accumulated postretirement benefit obligation	26,661	24,817
Amortization of transition obligation	13,950	14,013
Regulatory deferral	(4,460)	(5,204)
Net asset gain (loss) during the period deferred for future recognition	2,578	(3,414)
Actual return on plan assets	(8,772)	165
NET PERIODIC POSTRETIREMENT BENEFIT COST	$36,196	$37,579

The accumulated postretirement benefit obligation ("APBO") at December 31 was as follows:

THOUSANDS OF DOLLARS	1995	1994
Retirees and dependents	$ 224,249	$ 199,976
Fully eligible active plan participants	11,869	8,945
Other active plan participants	147,992	103,741
APBO	384,110	312,662
Plan assets at fair value	95,384	60,265
APBO in excess of plan assets	288,726	252,397
Unrecognized transition obligation at January 1, being amortized over 20 years	(237,162)	(252,229)
Unrecognized net gain (loss)	(43,197)	5,431
ACCRUED POSTRETIREMENT BENEFIT OBLIGATION	$ 8,367	$ 5,599
Discount rate	7.25%	8.5%
Estimated long-term rate of return on assets	8.75%	8.5%
Initial health care cost trend rate-under 65	11%	11%
nitial health care cost trend rate-over 65	10%	10%
ltimate health care cost trend rate	4.5%	5.5%

The assumed health care cost trend rate gradually decreases over eight years. The health care cost trend rate assumption has a significant effect on the amounts reported. Increasing the assumed health care cost trend rate by one percentage point would have increased the APBO as of December 31, 1995 by $29,577,000 and the annual net periodic postretirement benefit cost by $2,534,000.

NOTE 12. RELATED PARTY TRANSACTIONS

The Company and its subsidiaries participate in a consolidated cash management program. Any funds advanced to/from the Company are included in accounts and notes payable/receivable-affiliated companies and advances from affiliated company. The notes and advances are due upon demand and bear interest at a short-term rate as defined under intercompany loan agreements and a contractual understanding agreement between the Company and its subsidiaries. Net interest expense on these advances was $4,539,000 and $4,152,000 in 1995 and 1994, respectively.

The Company provides certain management services, such as corporate and financial advice and consultation, to subsidiaries at cost. The amounts charged to the subsidiaries were $2,062,000 and $1,726,000 in 1995 and 1994, respectively.

All of the coal production of the Bridger Mine ("Bridger") is sold to a steam electric generating plant owned by the Company and Idaho Power Company ("Idaho"). Sales to the plant were $136,411,000 in 1995 and $134,220,000 in 1994. The Company provided Bridger with management, administrative, engineering services and electricity on an as-needed basis. The amount charged for these services was $4,764,000 and $4,313,000 in 1995 and 1994, respectively. In addition, Bridger paid overriding royalties to the Company and Idaho of $614,000 and $746,000 in 1995 and 1994, respectively, pursuant to coal lease agreements.

During 1995, the Company entered into an agreement with its wholly owned subsidiary, Demand Side Receivables, Inc. ("DSRI") to sell all of its demand side receivable loans to DSRI at their discounted present values. The Company realized net proceeds of $28,734,000 and recorded a loss of $3,508,000, which is included in Miscellaneous Nonoperating Income. DSRI sold $23,400,000 of these receivables to outside parties and recorded a gain of $2,644,000, which is included in Equity in Earnings of Subsidiary Companies.

NOTE 13. ACQUISITIONS AND DISPOSITIONS BY SUBSIDIARIES

On December 12, 1995, Holdings purchased Powercor Australia Limited ("Powercor"), an electricity distributor in Australia, for $1.6 billion in cash and approximately $50 million of liabilities assumed. Powercor's service territory includes a portion of suburban Melbourne and the western and central regions of the State of Victoria and has approximately 540,000 customers.

The acquisition has been accounted for as a purchase and the results of operations of Powercor have been included in equity in subsidiary earnings since December 12, 1995.

The unaudited pro forma information as set forth below has been prepared by the Company based upon assumptions deemed proper by it and a preliminary allocation of the purchase price paid as though it had occurred on January 1, 1994. The unaudited pro forma results of operations are shown for illustrative purposes only and are not necessarily indicative of the future results of operations of the Company, or of the results of operations of the Company that would have actually occurred had the transaction been in effect as of the periods presented. Pro forma adjustments to equity in subsidiary earnings include: interest expense relating to the preacquisition activities was removed and interest expense relating to the acquisition debt was included; depreciation of fixed assets acquired was based on their estimated fair value; and amortization on a straight-line basis over a 40-year life of intangible assets relating to the purchase was included.

NOTES TO FINANCIAL STATEMENTS (Continued)

THOUSANDS OF DOLLARS/FOR THE YEAR	1995	1994
Equity in subsidiary earnings	$184,235	$ 73,804
Net income	497,667	453,074
Earnings on common stock	458,928	413,399

On September 27, 1995, holders of a majority of the 5,300,000 shares of outstanding common stock held by minority shareholders of Pacific Telecom voted in favor of the merger of a wholly owned subsidiary of Holdings into Pacific Telecom. Shareholders tendering shares pursuant to the merger were paid a total of $131 million, or $30 per share, and an accrued liability of $28 million was established by Pacific Telecom to cover estimated amounts payable to dissenters.

During 1995, Pacific Telecom purchased certain rural telephone exchange assets in Colorado, Washington and Oregon for approximately $376 million. On August 7, 1995, Pacific Telecom closed the sale of the stock of Alascom, Inc. ("Alascom") to AT&T Corp. A gain of $37.2 million from the sale of Alascom is included in equity in subsidiary earnings in 1995. Revenues and income from operations were $193 million and $37 million, respectively, for the seven months ended July 31, 1995, and $344 million and $81 million, respectively, for the year ended December 31, 1994.

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MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Intangible Plant**			
3				
4	301 Organization	441,908	441,908	0.00%
5	302 Franchises & Consents	79,423	83,832	5.55%
6	303 Miscellaneous Intangible Plant	1,307,984	2,258,301	72.66%
7				
8	**TOTAL Intangible Plant**	1,829,315	2,784,042	52.19%
9				
10	**Production Plant**			
11				
12	**Steam Production**			
13				
14	310 Land & Land Rights	832,157	878,966	5.63%
15	311 Structures & Improvements	9,522,089	10,241,964	7.56%
16	312 Boiler Plant Equipment	35,246,546	38,120,667	8.15%
17	313 Engines & Engine Driven Generators	0	0	
18	314 Turbogenerator Units	8,394,334	9,068,283	8.03%
19	315 Accessory Electric Equipment	4,291,818	4,552,773	6.08%
20	316 Miscellaneous Power Plant Equipment	817,770	690,023	-15.62%
21				
22	**TOTAL Steam Production Plant**	59,104,714	63,552,675	7.53%
23				
24	**Nuclear Production**			
25				
26	320 Land & Land Rights	0	0	
27	321 Structures & Improvements	0	0	
28	322 Reactor Plant Equipment	0	0	
29	323 Turbogenerator Units	0	0	
30	324 Accessory Electric Equipment	0	0	
31	325 Miscellaneous Power Plant Equipment	0	0	
32				
33	**TOTAL Nuclear Production Plant**	0	0	
34				
35	**Hydraulic Production**			
36				
37	330 Land & Land Rights	335,630	380,030	13.23%
38	331 Structures & Improvements	1,459,987	1,733,809	18.76%
39	332 Reservoirs, Dams & Waterways	5,405,328	5,854,905	8.32%
40	333 Water Wheels, Turbines & Generators	1,247,671	1,435,302	15.04%
41	334 Accessory Electric Equipment	396,683	422,251	6.45%
42	335 Miscellaneous Power Plant Equipment	88,834	65,035	-26.79%
43	336 Roads, Railroads & Bridges	195,675	249,214	27.36%
44				
45	**TOTAL Hydraulic Production**	9,129,808	10,140,548	11.07%
46				
47				
48				
49				
50				

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Account Number & Title		Last Year	This Year	% Change
Production Plant (cont.)				
Other Production				
340	Land & Land Rights	0	0	
341	Structures & Improvements	84	176	
342	Fuel Holders, Producers & Accessories	0	0	
343	Prime Movers	1,382	1,452	5.06%
344	Generators	2,659	3,117	17.21%
345	Accessory Electric Equipment	895	940	4.99%
346	Miscellaneous Power Plant Equipment	0	0	
	TOTAL Other Production Plant	5,020	5,685	13.24%
	TOTAL Production Plant	68,239,542	73,698,907	8.00%
Transmission Plant				
350	Land & Land Rights	860,803	939,928	9.19%
352	Structures & Improvements	388,648	465,163	19.69%
353	Station Equipment	9,274,737	10,686,684	15.22%
354	Towers & Fixtures	5,477,979	5,807,524	6.02%
355	Poles & Fixtures	3,899,151	4,764,055	22.18%
356	Overhead Conductors & Devices	8,551,403	9,371,426	9.59%
357	Underground Conduit	653	226	-65.39%
358	Underground Conductors & Devices	524	715	36.36%
359	Roads & Trails	179,852	208,506	15.93%
	TOTAL Transmission Plant	28,633,750	32,244,228	12.61%
Distribution Plant				
360	Land & Land Rights	217,746	217,981	0.11%
361	Structures & Improvements	412,526	640,593	55.29%
362	Station Equipment	8,626,692	9,926,542	15.07%
363	Storage Battery Equipment	0	0	
364	Poles, Towers & Fixtures	9,642,531	12,082,520	25.30%
365	Overhead Conductors & Devices	10,192,618	11,373,817	11.59%
366	Underground Conduit	2,518,961	3,644,594	44.69%
367	Underground Conductors & Devices	3,116,410	4,097,470	31.48%
368	Line Transformers	13,592,435	15,565,070	14.51%
369	Services	5,593,335	7,699,227	37.65%
370	Meters	2,240,039	2,791,675	24.63%
371	Installations on Customers' Premises	167,146	166,722	-0.25%
372	Leased Property on Customers' Premises	0	0	
373	Street Lighting & Signal Systems	516,863	605,522	17.15%
	TOTAL Distribution Plant	56,837,302	68,811,733	21.07%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

	Account Number & Title		Last Year	This Year	% Change
1	**General Plant**				
2					
3	389	Land & Land Rights	110,283	133,513	21.06%
4	390	Structures & Improvements	2,161,343	2,347,732	8.62%
5	391	Office Furniture & Equipment	2,009,779	2,414,744	20.15%
6	392	Transportation Equipment	488,162	643,290	31.78%
7	393	Stores Equipment	83,089	111,160	33.78%
8	394	Tools, Shop & Garage Equipment	509,596	710,395	39.40%
9	395	Laboratory Equipment	591,008	693,578	17.36%
10	396	Power Operated Equipment	876,647	1,047,197	19.45%
11	397	Communication Equipment	1,208,210	1,488,091	23.16%
12	398	Miscellaneous Equipment	40,884	49,912	22.08%
13	399	Other Tangible Property	6,458,627	7,790,054	20.61%
14					
15	**TOTAL General Plant**		14,537,628	17,429,667	19.89%
16					
17	**TOTAL Unclassified Plant**		2,673,463	2,509,323	-6.14%
18					
19	**TOTAL Electric Plant in Service**		172,751,000	197,477,900	14.31%

Sch. 20 MONTANA DEPRECIATION SUMMARY

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production		22,629,000	24,763,472	2.45%
3	Nuclear Production		0	0	0.00%
4	Hydraulic Production		3,145,000	3,458,125	1.85%
5	Other Production		1,000	785	3.08%
6	Transmission		8,130,000	9,195,763	2.36%
7	Distribution		14,823,000	17,324,360	3.16%
8	General		5,008,000	5,981,019	5.83%
9	**TOTAL**		53,736,000	60,723,524	

Sch. 21 MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	870,238	1,088,620	25.09%
3	152 Fuel Stock Expenses Undistributed			
4	153 Residuals			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)	1,166,622	1,277,058	9.47%
9	Transmission Plant (Estimated)	196,960	155,687	-20.96%
10	Distribution Plant (Estimated)	402,340	389,809	-3.11%
11	Assigned to Other	172,555	224,247	29.96%
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed	80,353	108,736	35.32%
16				
17	**TOTAL Materials & Supplies**	2,889,068	3,244,157	12.29%

Sch. 22 MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	89.6.17			
2	Order Number	5432			
3					
4	Common Equity		35.20%	12.30%	4.33%
5	Preferred Stock		7.60%	8.35%	0.63%
6	Long Term Debt		57.20%	8.45%	4.83%
7	Other		0.00%	0.00%	0.00%
8	**TOTAL**		100.00%		9.80%
9					
10	Actual at Year End				
11					
12	Common Equity		47.00%	12.30%	5.78%
13	Preferred Stock		7.00%	6.59%	0.46%
14	Long Term Debt		46.00%	7.70%	3.54%
15	Other		0.00%	0.00%	0.00%
16	**TOTAL**		100.00%		9.78%

Sch. 23 **STATEMENT OF CASH FLOWS**

	Description	This year	Last Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	504,466,484	467,473,590	7.91%
6	Depreciation	294,321,232	279,666,867	5.24%
7	Amortization	26,040,250	21,914,228	18.83%
8	Deferred Income Taxes - Net	35,977,348	79,052,472	-54.49%
9	Investment Tax Credit Adjustments - Net	(8,990,996)	(7,354,793)	-22.25%
10	Change in Operating Receivables - Net	(44,759,623)	971,719	-4706.23%
11	Change in Materials, Supplies & Inventories - Net	(13,580,555)	8,375,711	-262.14%
12	Change in Operating Payables & Accrued Liabilities - Net	63,284,381	(25,498,686)	348.19%
13	Allowance for Funds Used During Construction (AFUDC)			
14	Change in Other Assets & Liabilities - Net	5,299,092	15,363,504	-65.51%
15	Other Operating Activities (explained on attached page)	(191,035,459)	(88,204,022)	-116.58%
16	Net Cash Provided by/(Used in) Operating Activities	671,022,154	751,760,590	-10.74%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment			
20	(net of AFUDC & Capital Lease Related Acquisitions)	(441,609,263)	(680,827,566)	35.14%
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	25,626,933	35,467,549	-27.75%
23	Investments In and Advances to Affiliates	(241,000,000)	102,653,309	-334.77%
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	(5,740,697)	(20,675,796)	72.23%
27	Net Cash Provided by/(Used in) Investing Activities	(662,723,027)	(563,382,504)	-17.63%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	305,730,880	231,159,688	32.26%
32	Preferred Stock			
33	Common Stock	391,507	54,825,490	-99.29%
34	Other: Intercompany Borrowings		17,113,221	-100.00%
35	Net Increase in Short-Term Debt	248,846,759	169,433,375	46.87%
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(100,200,032)	(287,399,375)	65.14%
39	Preferred Stock	(55,825,925)		
40	Common Stock	(2,580,641)		
41	Other: Redemption Premium/Intercompany Borrowing	(54,196,020)	(335,000)	-16077.92%
42	Net Decrease in Short-Term Debt			
43	Dividends on Preferred Stock	(39,437,684)	(39,613,917)	0.44%
44	Dividends on Common Stock	(307,048,376)	(305,170,151)	-0.62%
45	Other Financing Activities (explained on attached page)			
46	Net Cash Provided by (Used in) Financing Activities	(4,319,532)	(159,986,669)	97.30%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	3,979,595	28,391,417	-85.98%
49	**Cash and Cash Equivalents at Beginning of Year**	(10,654,491)	(39,045,908)	72.71%
50	**Cash and Cash Equivalents at End of Year**	(6,674,896)	(10,654,491)	37.35%

Sch. 24

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	**FIRST MORTGAGE BONDS:**								
2	9-3/8% Yen Fin due 7/22/97	07/22/87	07/22/97	$50,000,000	$48,714,128	$50,000,000	5.40%	$3,599,000	7.20%
3	ARS Series due 11/1/02	09/16/82	11/01/2002	$50,000,000	$10,400,227	$13,234,000	5.92%	$1,724,920	13.03%
4	6-3/4% Series due 4/1/05	04/01/93	04/01/2005	$150,000,000	$144,118,206	$150,000,000	6.12%	$10,867,500	7.25%
5	8.271% Series due 10/1/10	04/15/92	10/01/2010	$48,972,000	$43,335,000	$43,335,000	6.71%	$3,584,238	8.27%
6	7.978% Series due 10/1/11	04/15/92	10/01/2011	$4,422,000	$3,924,000	$3,924,000	6.66%	$313,057	7.98%
7	8.493% Series due 10/1/12	04/15/92	10/01/2012	$19,772,000	$17,889,000	$17,889,000	6.78%	$1,519,313	8.49%
8	8.797% Series due 10/1/13	04/15/92	10/01/2013	$16,203,000	$14,823,000	$14,823,000	6.85%	$1,303,979	8.80%
9	8.734% Series due 10/1/14	04/15/92	10/01/2014	$28,218,000	$26,010,000	$26,010,000	6.84%	$2,271,713	8.73%
10	8.294% Series due 10/1/15	04/15/92	10/01/2015	$46,946,000	$43,428,000	$43,428,000	6.77%	$3,601,918	8.29%
11	8.635% Series due 10/1/16	04/15/92	10/01/2016	$18,750,000	$17,498,000	$17,498,000	6.84%	$1,510,952	8.63%
12	8.470% Series due 10/1/17	04/15/92	10/01/2017	$19,609,000	$18,381,000	$18,381,000	6.82%	$1,556,871	8.47%
13									
14				$452,892,000	$388,520,561	$398,522,000		$31,853,461	7.99%
15									
16	**SECURED MEDIUM-TERM NOTES:**								
17	8.60% Ser. B due 1/25/96	01/25/91	01/25/96	$1,000,000	$993,535	$1,000,000	5.38%	$87,620	8.76%
18	8.55% Ser. B due 2/1/96	01/30/91	02/01/96	$3,000,000	$2,977,605	$3,000,000	5.38%	$262,110	8.74%
19	8.57% Ser. B due 2/1/96	01/31/91	02/01/96	$11,000,000	$10,928,887	$11,000,000	5.38%	$960,520	8.73%
20	8.69% Ser. C due 7/16/96	07/16/91	07/16/96	$8,500,000	$8,441,215	$8,500,000	5.38%	$753,440	8.86%
21	8.65% Ser. B due 7/17/96	07/17/91	07/17/96	$1,000,000	$994,982	$1,000,000	5.38%	$87,760	8.78%
22	8.49% Ser. C due 8/15/96	08/06/91	08/15/96	$14,050,000	$13,952,831	$14,050,000	5.38%	$1,217,152	8.66%
23	8.43% Ser. A due 9/2/96	08/03/89	09/01/96	$5,000,000	$4,960,176	$5,000,000	5.38%	$429,200	8.58%
24	4.53% Ser. F due 9/16/96	09/14/93	09/16/96	$25,000,000	$24,461,042	$25,000,000	5.38%	$1,329,250	5.32%
25	4.53% Ser. F due 9/16/96	09/14/93	09/16/96	$25,000,000	$24,461,042	$25,000,000	5.38%	$1,329,250	5.32%
26	4.53% Ser. F due 9/16/96	09/14/93	09/16/96	$32,000,000	$31,310,134	$32,000,000	5.38%	$1,701,440	5.32%
27	4.53% Ser. F due 9/16/96	09/14/93	09/16/96	$40,000,000	$39,137,668	$40,000,000	5.38%	$2,126,800	5.32%
28	6.96% Ser. D due 1/22/97	02/14/92	01/22/97	$1,000,000	$942,433	$1,000,000	5.40%	$83,930	8.39%
29	7.00% Ser. D due 1/27/97	01/27/92	01/27/97	$15,000,000	$13,838,168	$15,000,000	5.40%	$1,343,400	8.96%
30	7.00% Ser. D due 1/27/97	01/31/92	01/27/97	$20,000,000	$18,117,558	$20,000,000	5.40%	$1,880,600	9.40%
31	6.99% Ser. D due 2/3/97	01/31/92	02/03/97	$1,500,000	$1,383,817	$1,500,000	5.40%	$134,175	8.95%
32	6.09% Ser. E due 4/15/97	10/21/92	04/15/97	$2,000,000	$1,855,647	$2,000,000	5.40%	$160,660	8.03%

Sch. 24

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	8.87% Ser. A due 6/20/97	06/20/91	06/20/97	$15,000,000	$14,917,158	$15,000,000	5.40%	$1,345,650	8.97%
2	8.85% Ser. A due 6/20/97	06/20/91	06/20/97	$20,000,000	$19,909,544	$20,000,000	5.40%	$1,793,800	8.97%
3	8.78% Ser. B due 6/30/97	06/28/91	06/30/97	$7,000,000	$6,961,340	$7,000,000	5.40%	$623,070	8.90%
4	8.84% Ser. B due 7/2/97	07/02/91	07/02/97	$2,000,000	$1,988,965	$2,000,000	5.40%	$179,220	8.96%
5	6.12% Ser. E due 9/29/97	09/29/92	09/29/97	$3,500,000	$3,082,441	$3,500,000	5.40%	$320,110	9.15%
6	6.12% Ser. E due 9/29/97	09/29/92	09/29/97	$10,000,000	$8,806,975	$10,000,000	5.40%	$914,600	9.15%
7	6.12% Ser. E due 9/29/97	09/29/92	09/29/97	$10,000,000	$8,806,975	$10,000,000	5.40%	$914,600	9.15%
8	6.12% Ser. E due 9/29/97	09/29/92	09/29/97	$10,000,000	$8,806,975	$10,000,000	5.40%	$914,600	9.15%
9	6.14% Ser. E due 9/29/97	09/29/92	09/29/97	$10,000,000	$8,806,975	$10,000,000	5.40%	$916,800	9.17%
10	5.88% Ser. E due 10/15/97	10/15/92	10/15/97	$12,000,000	$11,127,884	$12,000,000	5.40%	$866,520	7.22%
11	5.88% Ser. E due 10/15/97	10/15/92	10/15/97	$1,000,000	$927,324	$1,000,000	5.40%	$72,210	7.22%
12	6.00% Ser. E due 10/15/97	10/15/92	10/15/97	$2,300,000	$2,132,845	$2,300,000	5.40%	$168,981	7.35%
13	8.75% Ser. B due 2/12/98	02/12/91	02/12/98	$15,000,000	$14,873,027	$15,000,000	5.51%	$1,337,250	8.92%
14	8.75% Ser. B due 2/12/98	02/12/91	02/12/98	$15,000,000	$14,873,027	$15,000,000	5.51%	$1,337,250	8.92%
15	8.75% Ser. B due 2/12/98	02/12/91	02/12/98	$15,000,000	$14,880,527	$15,000,000	5.51%	$1,335,750	8.91%
16	8.75% Ser. A due 2/12/98	02/12/91	02/12/98	$10,000,000	$9,915,352	$10,000,000	5.51%	$891,500	8.92%
17	8.75% Ser. A due 2/12/98	02/12/91	02/12/98	$5,000,000	$4,957,676	$5,000,000	5.51%	$445,750	8.92%
18	8.81% Ser. C due 3/5/98	08/05/91	03/05/98	$7,000,000	$6,948,089	$7,000,000	5.51%	$626,850	8.96%
19	8.94% Ser. A due 6/25/98	06/25/91	06/25/98	$15,000,000	$14,909,658	$15,000,000	5.51%	$1,358,700	9.06%
20	8.95% Ser. A due 6/30/98	06/26/91	06/30/98	$20,000,000	$19,879,544	$20,000,000	5.51%	$1,813,600	9.07%
21	8.95% Ser. A due 6/30/98	06/26/91	06/30/98	$5,000,000	$4,972,386	$5,000,000	5.51%	$452,900	9.06%
22	8.90% Ser. C due 6/30/98	06/27/91	06/30/98	$25,000,000	$24,802,102	$25,000,000	5.51%	$2,263,750	9.06%
23	8.96% Ser. A due 7/3/98	07/03/91	07/03/98	$8,000,000	$7,951,860	$8,000,000	5.51%	$726,240	9.08%
24	8.94% Ser. C due 7/6/98	07/05/91	07/06/98	$5,000,000	$4,960,420	$5,000,000	5.51%	$454,750	9.10%
25	8.89% Ser. C due 7/20/98	07/19/91	07/20/98	$5,000,000	$4,960,420	$5,000,000	5.51%	$452,250	9.05%
26	8.82% Ser. C due 8/3/98	08/02/91	08/03/98	$5,000,000	$4,960,420	$5,000,000	5.51%	$448,750	8.98%
27	8.83% Ser. C due 9/1/98	08/06/91	09/01/98	$18,000,000	$17,857,513	$18,000,000	5.51%	$1,617,300	8.99%
28	8.83% Ser. C due 9/1/98	08/06/91	09/01/98	$4,000,000	$3,968,336	$4,000,000	5.51%	$359,400	8.99%
29	8.83% Ser. C due 9/1/98	08/06/91	09/01/98	$4,000,000	$3,968,336	$4,000,000	5.51%	$359,400	8.99%
30	8.83% Ser. C due 9/1/98	08/06/91	09/01/98	$4,000,000	$3,970,336	$4,000,000	5.51%	$359,000	8.98%
31	7.45% Ser. D due 1/22/99	01/31/92	01/22/99	$5,000,000	$4,574,389	$5,000,000	5.62%	$456,100	9.12%
32	7.45% Ser. D due 1/22/99	01/31/92	01/22/99	$10,000,000	$8,548,779	$10,000,000	5.62%	$1,042,200	10.42%

Sch. 24

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	7.35% Ser. D due 2/1/99	01/31/92	02/01/99	$4,000,000	$3,419,512	$4,000,000	5.62%	$412,440	10.31%
2	7.45% Ser. D due 2/4/99	02/14/92	02/04/99	$20,000,000	$18,828,651	$20,000,000	5.62%	$1,716,000	8.58%
3	7.46% Ser. D due 2/15/99	02/14/92	02/15/99	$10,000,000	$8,414,326	$10,000,000	5.62%	$1,074,000	10.74%
4	7.40% Ser. D due 2/15/99	02/14/92	02/15/99	$5,000,000	$4,707,163	$5,000,000	5.62%	$426,400	8.53%
5	7.40% Ser. D due 2/15/99	02/14/92	02/15/99	$5,000,000	$4,707,163	$5,000,000	5.62%	$426,400	8.53%
6	7.50% Ser. D due 2/15/99	02/14/92	02/15/99	$5,000,000	$4,707,163	$5,000,000	5.62%	$431,600	8.63%
7	7.49% Ser. D due 2/15/99	02/14/92	02/15/99	$30,000,000	$27,942,981	$30,000,000	5.62%	$2,647,200	8.82%
8	7.45% Ser. D due 2/15/99	02/14/92	02/15/99	$20,000,000	$18,728,651	$20,000,000	5.62%	$1,736,200	8.68%
9	7.54% Ser. D due 2/15/99	02/14/92	02/15/99	$15,000,000	$13,121,489	$15,000,000	5.62%	$1,511,550	10.08%
10	9-1/2% Ser. A due 5/20/99	05/19/89	05/20/99	$60,000,000	$59,177,495	$60,000,000	5.62%	$5,830,200	9.72%
11	9.48% Ser. A due 5/25/99	05/25/89	05/25/99	$15,000,000	$14,869,277	$15,000,000	5.62%	$1,442,700	9.62%
12	9-1/2% Ser. A due 6/1/99	05/25/89	06/01/99	$15,000,000	$14,794,374	$15,000,000	5.62%	$1,457,550	9.72%
13	9-1/2% Ser. A due 6/1/99	05/25/89	06/01/99	$15,000,000	$14,930,177	$15,000,000	5.62%	$1,435,950	9.57%
14	9.40% Ser. A due 6/1/99	05/26/89	06/01/99	$15,000,000	$14,798,124	$15,000,000	5.62%	$1,441,800	9.61%
15	8.55% Ser. A due 8/10/99	08/04/89	08/10/99	$2,000,000	$1,982,570	$2,000,000	5.62%	$173,640	8.68%
16	8.59% Ser. A due 9/1/99	08/03/89	09/01/99	$10,000,000	$9,915,352	$10,000,000	5.62%	$871,900	8.72%
17	6.51% Ser. E due 9/23/99	09/23/92	09/23/99	$15,000,000	$13,195,463	$15,000,000	5.62%	$1,327,800	8.85%
18	6.54% Ser. E due 9/27/99	09/25/92	09/27/99	$5,000,000	$4,398,488	$5,000,000	5.62%	$444,250	8.89%
19	6.53% Ser. E due 9/27/99	09/25/92	09/27/99	$5,000,000	$4,398,488	$5,000,000	5.62%	$443,700	8.87%
20	6.55% Ser. E due 9/28/99	09/28/92	09/28/99	$1,200,000	$1,055,637	$1,200,000	5.62%	$106,752	8.90%
21	7.21% Ser. E due 1/19/00	01/19/93	01/19/2000	$25,000,000	$23,168,715	$25,000,000	5.74%	$2,156,500	8.63%
22	7.11% Ser. E due 1/20/00	01/20/93	01/20/2000	$10,000,000	$9,267,486	$10,000,000	5.74%	$852,100	8.52%
23	7.13% Ser. E due 1/20/00	01/20/93	01/20/2000	$10,000,000	$9,267,486	$10,000,000	5.74%	$854,200	8.54%
24	7.07% Ser. E due 1/25/00	01/22/93	01/25/2000	$10,500,000	$9,730,860	$10,500,000	5.74%	$890,295	8.48%
25	6.99% Ser. E due 1/25/00	01/25/93	01/25/2000	$10,000,000	$9,692,579	$10,000,000	5.74%	$756,400	7.56%
26	6.97% Ser. E due 1/28/00	01/28/93	01/28/2000	$1,000,000	$971,670	$1,000,000	5.74%	$74,980	7.50%
27	5.85% Ser. F due 4/17/00	08/02/93	04/17/2000	$3,000,000	$2,817,905	$3,000,000	5.74%	$208,800	6.96%
28	5.85% Ser. F due 4/17/00	08/02/93	04/17/2000	$3,000,000	$2,817,905	$3,000,000	5.74%	$208,800	6.96%
29	5.85% Ser. F due 4/17/00	08/02/93	04/17/2000	$5,000,000	$4,696,507	$5,000,000	5.74%	$348,000	6.96%
30	5.85% Ser. F due 4/17/00	08/02/93	04/17/2000	$5,000,000	$4,696,507	$5,000,000	5.74%	$348,000	6.96%
31	6.05% Ser. F due 4/17/00	08/13/93	04/17/2000	$15,000,000	$14,089,522	$15,000,000	5.74%	$1,075,200	7.17%
32	6.05% Ser. F due 4/17/00	08/13/93	04/17/2000	$15,000,000	$14,089,522	$15,000,000	5.74%	$1,075,200	7.17%

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	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	6.05% Ser. F due 4/17/00	08/13/93	04/17/2000	$25,000,000	$24,170,621	$25,000,000	5.74%	$1,662,500	6.65%
2	6.05% Ser. F due 4/17/00	08/13/93	04/17/2000	$5,000,000	$4,874,722	$5,000,000	5.74%	$325,050	6.50%
3	6.86% Ser. E due 9/11/00	09/10/92	09/11/2000	$10,000,000	$8,796,975	$10,000,000	5.74%	$900,200	9.00%
4	6.55% Ser. E due 9/15/00	09/16/92	09/15/2000	$5,000,000	$4,398,488	$5,000,000	5.74%	$433,300	8.67%
5	8.90% Ser. B due 2/15/01	02/12/91	02/15/2001	$20,000,000	$19,825,703	$20,000,000	5.74%	$1,806,800	9.03%
6	8.90% Ser. B due 2/15/01	02/12/91	02/15/2001	$20,000,000	$19,830,703	$20,000,000	5.74%	$1,806,000	9.03%
7	8.88% Ser. B due 2/15/01	02/12/91	02/15/2001	$20,000,000	$19,825,703	$20,000,000	5.74%	$1,802,800	9.01%
8	8.90% Ser. B due 2/15/01	02/13/91	02/15/2001	$20,000,000	$19,825,703	$20,000,000	5.74%	$1,806,800	9.03%
9	9.10% Ser. A due 3/1/01	06/25/91	03/01/2001	$5,000,000	$4,969,886	$5,000,000	5.74%	$459,650	9.19%
10	6.02% Ser. F due 5/15/01	07/27/93	05/15/2001	$4,500,000	$4,224,607	$4,500,000	5.74%	$316,485	7.03%
11	9.12% Ser. C due 7/5/01	07/05/91	07/05/2001	$5,000,000	$4,959,170	$5,000,000	5.74%	$462,350	9.25%
12	9.12% Ser. C due 7/5/01	07/05/91	07/05/2001	$10,000,000	$9,918,341	$10,000,000	5.74%	$924,700	9.25%
13	9.06% Ser. B due 7/9/01	07/09/91	07/09/2001	$1,000,000	$993,982	$1,000,000	5.74%	$91,530	9.15%
14	9.15% Ser. C due 7/16/01	07/16/91	07/16/2001	$3,000,000	$2,975,502	$3,000,000	5.74%	$278,310	9.28%
15	9.17% Ser. B due 7/17/01	07/17/91	07/17/2001	$1,000,000	$993,732	$1,000,000	5.74%	$92,670	9.27%
16	9.06% Ser. C due 7/23/01	07/23/91	07/23/2001	$1,000,000	$991,834	$1,000,000	5.74%	$91,870	9.19%
17	9.09% Ser. C due 7/24/01	07/24/91	07/24/2001	$1,000,000	$991,834	$1,000,000	5.74%	$92,170	9.22%
18	9.10% Ser. C due 7/30/01	07/30/91	07/30/2001	$5,000,000	$4,959,170	$5,000,000	5.74%	$461,350	9.23%
19	7.50% Ser. E due 8/1/01	11/06/92	08/01/2001	$2,000,000	$1,853,064	$2,000,000	5.74%	$173,880	8.69%
20	8.99% Ser. C due 8/7/01	08/07/91	08/07/2001	$3,000,000	$2,975,502	$3,000,000	5.74%	$273,480	9.12%
21	9.00% Ser. C due 8/8/01	08/08/91	08/08/2001	$500,000	$495,917	$500,000	5.74%	$45,630	9.13%
22	9.00% Ser. B due 8/8/01	08/08/91	08/08/2001	$2,500,000	$2,484,331	$2,500,000	5.74%	$227,425	9.10%
23	7.20% Ser. D due 8/15/02	08/14/92	08/15/2002	$12,000,000	$11,318,967	$12,000,000	5.92%	$964,440	8.04%
24	7.20% Ser. D due 8/15/02	08/14/92	08/15/2002	$6,500,000	$6,131,108	$6,500,000	5.92%	$522,405	8.04%
25	7.20% Ser. D due 8/15/02	08/14/92	08/15/2002	$10,000,000	$9,432,473	$10,000,000	5.92%	$803,700	8.04%
26	7.20% Ser. D due 8/15/02	08/14/92	08/15/2002	$6,000,000	$5,659,483	$6,000,000	5.92%	$482,220	8.04%
27	7.18% Ser. D due 8/15/02	08/14/92	08/15/2002	$10,000,000	$9,432,473	$10,000,000	5.92%	$801,600	8.02%
28	7.18% Ser. D due 8/15/02	08/14/92	08/15/2002	$3,500,000	$3,301,365	$3,500,000	5.92%	$280,560	8.02%
29	7.12% Ser. D due 8/15/02	08/14/92	08/15/2002	$4,000,000	$3,772,989	$4,000,000	5.92%	$318,120	7.95%
30	7.25% Ser. E due 9/9/02	09/08/92	09/09/2002	$20,000,000	$18,842,236	$20,000,000	5.92%	$1,621,200	8.11%
31	7.25% Ser. E due 9/9/02	09/04/92	09/09/2002	$20,000,000	$17,591,269	$20,000,000	5.92%	$1,822,200	9.11%
32	7.21% Ser. E due 9/9/02	09/09/92	09/09/2002	$10,000,000	$8,794,475	$10,000,000	5.92%	$906,900	9.07%

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	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	7.14% Ser. E due 9/10/02	09/10/92	09/10/2002	$1,500,000	$1,319,171	$1,500,000	5.92%	$134,895	8.99%
2	6.98% Ser. E due 9/16/02	09/15/92	09/16/2002	$10,000,000	$8,794,475	$10,000,000	5.92%	$881,900	8.82%
3	6.97% Ser. E due 9/16/02	09/15/92	09/16/2002	$2,000,000	$1,758,895	$2,000,000	5.92%	$176,160	8.81%
4	6.95% Ser. E due 9/16/02	09/16/92	09/16/2002	$10,000,000	$8,794,475	$10,000,000	5.92%	$878,600	8.79%
5	7.00% Ser. E due 9/17/02	09/17/92	09/17/2002	$1,000,000	$879,448	$1,000,000	5.92%	$88,410	8.84%
6	6.97% Ser. E due 9/23/02	09/21/92	09/23/2002	$1,500,000	$1,319,171	$1,500,000	5.92%	$132,120	8.81%
7	7.40% Ser. E due 1/22/03	01/22/93	01/22/2003	$1,000,000	$926,499	$1,000,000	5.92%	$85,060	8.51%
8	7.36% Ser. E due 1/27/03	01/26/93	01/27/2003	$3,000,000	$2,914,260	$3,000,000	5.92%	$233,280	7.78%
9	6.34% Ser. F due 7/28/03	07/28/93	07/28/2003	$19,000,000	$17,832,478	$19,000,000	5.92%	$1,370,470	7.21%
10	6.34% Ser. F due 7/28/03	07/28/93	07/28/2003	$4,000,000	$3,754,206	$4,000,000	5.92%	$288,520	7.21%
11	6.34% Ser. F due 7/28/03	07/28/93	07/28/2003	$2,000,000	$1,877,103	$2,000,000	5.92%	$144,260	7.21%
12	6.34% Ser. F due 7/28/03	07/28/93	07/28/2003	$2,000,000	$1,877,103	$2,000,000	5.92%	$144,260	7.21%
13	6.34% Ser. F due 7/28/03	07/21/93	07/28/2003	$10,000,000	$9,385,515	$10,000,000	5.92%	$721,300	7.21%
14	6.31% Ser. F due 7/28/03	07/28/93	07/28/2003	$6,000,000	$5,631,308	$6,000,000	5.92%	$430,920	7.18%
15	6.31% Ser. F due 7/28/03	07/28/93	07/28/2003	$18,000,000	$16,893,926	$18,000,000	5.92%	$1,292,760	7.18%
16	6.31% Ser. F due 7/28/03	07/28/93	07/28/2003	$18,000,000	$16,893,926	$18,000,000	5.92%	$1,292,760	7.18%
17	6.31% Ser. F due 7/28/03	07/28/93	07/28/2003	$1,000,000	$938,552	$1,000,000	5.92%	$71,820	7.18%
18	9.00% Ser. C due 9/1/03	06/10/91	09/01/2003	$55,226,000	$35,322,633	$37,100,714	5.92%	$3,592,833	9.68%
19	7.03% Ser. E due 10/15/03	10/15/92	10/15/2003	$5,000,000	$4,630,369	$5,000,000	5.92%	$402,800	8.06%
20	7.27% Ser. E due 10/21/03	10/21/92	10/21/2003	$2,000,000	$1,852,147	$2,000,000	5.92%	$166,160	8.31%
21	7.39% Ser. E due 10/21/03	10/21/92	10/21/2003	$5,000,000	$4,630,369	$5,000,000	5.92%	$421,700	8.43%
22	7.30% Ser. E due 10/22/03	10/22/92	10/22/2003	$2,000,000	$1,852,147	$2,000,000	5.92%	$166,800	8.34%
23	7.86% Ser. D due 2/16/04	02/14/92	02/16/2004	$2,500,000	$2,136,570	$2,500,000	5.92%	$249,075	9.96%
24	7.81% Ser. D due 2/16/04	02/14/92	02/16/2004	$20,000,000	$17,245,673	$20,000,000	5.92%	$1,957,000	9.79%
25	7.79% Ser. D due 2/16/04	02/14/92	02/16/2004	$6,000,000	$5,647,095	$6,000,000	5.92%	$515,100	8.59%
26	7.75% Ser. D due 2/16/04	02/14/92	02/16/2004	$3,000,000	$2,823,548	$3,000,000	5.92%	$256,290	8.54%
27	7.32% Ser. E due 9/3/04	09/04/92	09/03/2004	$7,500,000	$7,065,838	$7,500,000	5.92%	$606,225	8.08%
28	7.11% Ser. E due 9/24/04	09/24/92	09/24/2004	$6,500,000	$5,716,409	$6,500,000	5.92%	$568,945	8.75%
29	7.30% Ser. E due 10/22/04	10/22/92	10/22/2004	$10,000,000	$9,260,737	$10,000,000	5.92%	$828,400	8.28%
30	7.30% Ser. E due 10/22/04	10/22/92	10/22/2004	$10,000,000	$9,260,737	$10,000,000	5.92%	$828,400	8.28%
31	7.66% Ser. E due 10/22/04	11/06/92	10/22/2004	$5,000,000	$4,631,411	$5,000,000	5.92%	$433,000	8.66%
32	7.53% Ser. E due 10/26/04	10/26/92	10/26/2004	$750,000	$694,555	$750,000	5.92%	$63,945	8.53%

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	7.71% Ser. E due 10/27/04	10/27/92	10/27/2004	$3,000,000	$2,778,221	$3,000,000	5.92%	$261,480	8.72%
2	7.71% Ser. E due 10/27/04	10/27/92	10/27/2004	$3,250,000	$3,009,740	$3,250,000	5.92%	$283,270	8.72%
3	7.60% Ser. E due 11/1/04	11/06/92	11/01/2004	$1,000,000	$926,282	$1,000,000	5.92%	$85,970	8.60%
4	7.72% Ser. E due 11/2/04	11/02/92	11/02/2004	$1,500,000	$1,389,423	$1,500,000	5.92%	$130,845	8.72%
5	7.43% Ser. E due 1/24/05	01/22/93	01/24/2005	$1,000,000	$926,499	$1,000,000	6.12%	$84,150	8.42%
6	7.43% Ser. E due 1/24/05	01/22/93	01/24/2005	$2,500,000	$2,316,247	$2,500,000	6.12%	$210,375	8.42%
7	7.34% Ser. E due 10/17/05	10/15/92	10/17/2005	$5,000,000	$4,630,369	$5,000,000	6.12%	$413,950	8.28%
8	7.36% Ser. E due 10/17/05	10/15/92	10/17/2005	$5,000,000	$4,630,369	$5,000,000	6.12%	$415,000	8.30%
9	7.67% Ser. C due 1/10/07	01/10/92	01/10/2007	$5,724,000	$4,903,598	$5,724,000	6.12%	$542,635	9.48%
10	6.625% Ser. G due 6/1/07	06/09/95	06/01/2007	$100,000,000	$97,222,726	$100,000,000	6.12%	$6,970,000	6.97%
11	7.43% Ser. E due 9/11/07	09/11/92	09/11/2007	$2,000,000	$1,758,395	$2,000,000	6.12%	$178,100	8.91%
12	7.22% Ser. E due 9/18/07	09/18/92	09/18/2007	$2,500,000	$2,197,994	$2,500,000	6.12%	$216,875	8.68%
13	7.27% Ser. E due 9/24/07	09/22/92	09/24/2007	$4,000,000	$3,516,790	$4,000,000	6.12%	$349,200	8.73%
14	9.15% Ser. C due 8/9/11	08/09/91	08/09/2011	$8,000,000	$7,924,673	$8,000,000	6.32%	$740,320	9.25%
15	8.95% Ser. C due 9/1/11	08/16/91	09/01/2011	$25,000,000	$24,824,602	$25,000,000	6.32%	$2,256,500	9.03%
16	8.95% Ser. C due 9/1/11	08/16/91	09/01/2011	$20,000,000	$19,867,882	$20,000,000	6.32%	$1,804,400	9.02%
17	8.92% Ser. C due 9/1/11	08/16/91	09/01/2011	$20,000,000	$19,811,682	$20,000,000	6.32%	$1,804,600	9.02%
18	8.29% Ser. C due 12/30/11	12/31/91	12/30/2011	$3,000,000	$2,566,175	$3,000,000	6.32%	$299,160	9.97%
19	8.26% Ser. C due 1/10/12	01/09/92	01/10/2012	$1,000,000	$855,423	$1,000,000	6.32%	$99,380	9.94%
20	8.28% Ser. C due 1/10/12	01/10/92	01/10/2012	$2,000,000	$1,712,847	$2,000,000	6.32%	$198,940	9.95%
21	8.25% Ser. C due 2/1/12	01/15/92	02/01/2012	$3,000,000	$2,566,270	$3,000,000	6.32%	$297,810	9.93%
22	8.13% Ser. E due 1/22/13	01/20/93	01/22/2013	$10,000,000	$9,252,486	$10,000,000	6.32%	$893,900	8.94%
23	7.25% Ser. F due 8/1/13	07/28/93	08/01/2013	$10,000,000	$9,373,015	$10,000,000	6.32%	$787,800	7.88%
24	7.25% Ser. F due 8/1/13	07/28/93	08/01/2013	$10,000,000	$9,373,015	$10,000,000	6.32%	$787,800	7.88%
25	7.25% Ser. F due 8/1/13	07/28/93	08/01/2013	$10,000,000	$9,373,015	$10,000,000	6.32%	$787,800	7.88%
26	7.25% Ser. F due 8/1/13	07/28/93	08/01/2013	$10,000,000	$9,373,015	$10,000,000	6.32%	$787,800	7.88%
27	8.53% Ser. C due 12/16/21	12/16/91	12/16/2021	$15,000,000	$12,830,877	$15,000,000	6.60%	$1,509,900	10.07%
28	8.375% Ser. C due 12/31/21	12/31/91	12/31/2021	$5,000,000	$4,276,959	$5,000,000	6.60%	$494,450	9.89%
29	8.26% Ser. C due 1/7/22	01/08/92	01/07/2022	$5,000,000	$4,282,117	$5,000,000	6.60%	$487,250	9.75%
30	8.27% Ser. C due 1/10/22	01/09/92	01/10/2022	$4,000,000	$3,421,693	$4,000,000	6.60%	$390,720	9.77%
31	8.05% Ser. E due 9/1/22	09/18/92	09/01/2022	$15,000,000	$13,172,963	$15,000,000	6.60%	$1,388,700	9.26%
32	8.07% Ser. E due 9/9/22	09/09/92	09/09/2022	$8,000,000	$7,025,580	$8,000,000	6.60%	$742,400	9.28%

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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	8.12% Ser. E due 9/9/22	09/11/92	09/09/2022	$50,000,000	$43,909,875	$50,000,000	6.60%	$4,668,000	9.34%
2	8.11% Ser. E due 9/9/22	09/11/92	09/09/2022	$12,000,000	$10,538,370	$12,000,000	6.60%	$1,119,000	9.33%
3	8.05% Ser. E due 9/14/22	09/14/92	09/14/2022	$10,000,000	$8,781,975	$10,000,000	6.60%	$925,800	9.26%
4	8.08% Ser. E due 10/14/22	10/15/92	10/14/2022	$26,000,000	$22,852,821	$26,000,000	6.60%	$2,413,580	9.28%
5	8.08% Ser. E due 10/14/22	10/15/92	10/14/2022	$25,000,000	$22,738,182	$25,000,000	6.60%	$2,238,250	8.95%
6	8.23% Ser. E due 1/20/23	01/20/93	01/20/2023	$5,000,000	$4,626,243	$5,000,000	6.60%	$447,550	8.95%
7	8.23% Ser. E due 1/20/23	01/29/93	01/20/2023	$4,000,000	$3,962,241	$4,000,000	6.60%	$332,640	8.32%
8	7.26% Ser. F due 7/21/23	07/22/93	07/21/2023	$27,000,000	$25,307,139	$27,000,000	6.60%	$2,107,080	7.80%
9	7.26% Ser. F due 7/21/23	07/22/93	07/21/2023	$11,000,000	$10,310,316	$11,000,000	6.60%	$858,440	7.80%
10	7.40% Ser. F due 7/28/23	07/28/93	07/28/2023	$2,000,000	$1,874,603	$2,000,000	6.60%	$159,040	7.95%
11	7.37% Ser. F due 8/11/23	08/11/93	08/11/2023	$15,500,000	$14,528,173	$15,500,000	6.60%	$1,227,600	7.92%
12	7.23% Ser. F due 8/16/23	08/16/93	08/16/2023	$15,000,000	$14,594,165	$15,000,000	6.60%	$1,118,550	7.46%
13	7.24% Ser. F due 8/16/23	08/16/93	08/16/2023	$30,000,000	$29,188,329	$30,000,000	6.60%	$2,240,100	7.47%
14	6.75% Ser. F due 9/14/23	09/14/93	09/14/2023	$5,000,000	$4,927,581	$5,000,000	6.60%	$343,250	6.87%
15	6.75% Ser. F due 9/14/23	09/14/93	09/14/2023	$2,000,000	$1,984,700	$2,000,000	6.60%	$136,200	6.81%
16	6.72% Ser. F due 9/14/23	09/14/93	09/14/2023	$2,000,000	$1,984,700	$2,000,000	6.60%	$135,600	6.78%
17	6.75% Ser. F due 10/26/23	10/26/93	10/26/2023	$20,000,000	$19,847,674	$20,000,000	6.60%	$1,362,000	6.81%
18	6.75% Ser. F due 10/26/23	10/26/93	10/26/2023	$16,000,000	$15,878,139	$16,000,000	6.60%	$1,089,600	6.81%
19	6.75% Ser. F due 10/26/23	10/26/93	10/26/2023	$12,000,000	$11,908,604	$12,000,000	6.60%	$817,200	6.81%
20	8.625% Ser. F due 12/13/24	12/13/94	12/13/2024	$20,000,000	$19,350,401	$20,000,000	6.60%	$1,787,600	8.94%
21									
22				$2,044,500,000	$1,920,521,798	$2,026,374,714		$169,973,688	8.39%
23									
24	**POLL. CTRL. OBLIGATIONS SECURED BY PLEDGED FIRST MORTGAGE BONDS:**								
25	Var. Rate Moffat 1994	11/17/94	05/01/2013	$40,655,000	$39,713,720	$40,655,000	4.41%	$1,908,752	4.69%
26	5-5/8% Series due 11/21 Lincol	11/15/93	11/01/2021	$8,300,000	$7,459,117	$8,300,000	6.42%	$531,864	6.41%
27	5.65% Series due 11/23 Emery	11/15/93	11/01/2023	$46,500,000	$42,033,154	$46,500,000	6.25%	$2,962,980	6.37%
28	5-5/8% Series due 11/23 Emery	11/15/93	11/01/2023	$16,400,000	$14,565,392	$16,400,000	6.18%	$1,061,900	6.48%
29	Var. Rate Sweetwater 1994	11/17/94	11/01/2024	$21,260,000	$20,661,385	$21,260,000	4.54%	$1,023,669	4.82%
30	Var. Rate Converse 1994	11/17/94	11/01/2024	$8,190,000	$7,894,191	$8,190,000	4.54%	$398,607	4.87%
31	Var. Rate Emery 1994	11/17/94	11/01/2024	$121,940,000	$116,740,249	$121,940,000	4.39%	$5,799,466	4.76%
32	Var. Rate Carbon 1994	11/17/94	11/01/2024	$9,365,000	$9,100,198	$9,365,000	4.41%	$438,657	4.68%

Sch. 24

LONG TERM DEBT

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	Var. Rate Lincoln 1994	11/17/94	11/01/2024	$15,060,000	$14,556,007	$15,060,000	4.54%	$730,259	4.85%
2									
3				$287,670,000	$272,723,413	$287,670,000		$14,856,154	5.16%
4									
5	**POLLUTION CONTROL REVENUE BONDS:**								
6	Var. Rate Sweetwater 1992A	09/29/92	04/01/2005	$9,335,000	$9,053,264	$9,335,000	3.59%	$411,767	4.41%
7	Var. Rate Sweetwater 1992B	09/29/92	12/01/2005	$6,305,000	$6,068,787	$6,305,000	3.70%	$289,841	4.60%
8	Var. Rate Converse 1992	09/29/92	07/01/2006	$22,485,000	$21,987,426	$22,485,000	3.75%	$1,006,653	4.48%
9	Var. Rate Sweetwater 1988B	01/01/88	01/01/2014	$11,500,000	$11,022,928	$11,500,000	3.82%	$533,255	4.64%
10	Var. Rate Converse 1988	01/01/88	01/01/2014	$17,000,000	$16,264,181	$17,000,000	3.57%	$741,880	4.36%
11	Var. Rate Sweetwater C	12/01/84	12/01/2014	$15,000,000	$14,772,113	$15,000,000	4.45%	$759,000	5.06%
12	Var. Rate Emery Co. 1991	05/23/91	07/01/2015	$45,000,000	$51,268,033	$45,000,000	3.75%	$3,847,050	8.55%
13	Var. Rate Sweetwater 1990A	07/25/90	07/01/2015	$70,000,000	$68,544,128	$70,000,000	4.34%	$3,526,600	5.04%
14	Var. Rate Lincoln Co. 1991	01/17/91	01/01/2016	$45,000,000	$51,358,959	$45,000,000	3.59%	$3,764,250	8.37%
15	Var. Rate Forsyth 1986	12/01/86	12/01/2016	$8,500,000	$8,195,176	$8,500,000	4.60%	$455,600	5.36%
16	Var. Rate Sweetwater A	01/01/88	01/01/2017	$50,000,000	$48,695,456	$50,000,000	3.72%	$2,233,500	4.47%
17	Var. Rate Forsyth 1988	01/01/88	01/01/2018	$45,000,000	$43,606,519	$45,000,000	3.99%	$2,698,200	6.00%
18	Var. Rate Gillette (Wyodak)	01/01/88	01/01/2018	$63,000,000	$39,842,082	$41,200,000	3.55%	$3,713,768	9.01%
19	Var. Rate Sweetwater 1990A	07/26/90	07/01/2019	$21,100,000	$17,940,157	$18,600,000	3.81%	$839,232	4.51%
20	Var. Rate Converse 1995	11/17/95	11/01/2025	$5,300,000	$5,263,517	$5,300,000	4.71%	$252,015	4.76%
21	Var. Rate Lincoln 1995	11/17/95	11/01/2025	$22,000,000	$21,861,289	$22,000,000	4.71%	$1,045,220	4.75%
22	Var. Rate Sweetwater 1995	12/14/95	11/01/2025	$24,400,000	$24,380,998	$24,400,000	5.10%	$1,244,888	5.10%
23									
24				$480,925,000	$460,125,013	$456,625,000		$27,362,719	5.99%
25									
26	**OTHER LONG-TERM DEBT:**								
27	8.375% QUIDS Series A	05/31/95	06/30/2035	$120,000,000	$115,676,396	$120,000,000	6.67%	$10,438,531	8.70%
28	8.55% QUIDS Series B	10/05/95	12/31/2025	$55,825,925	$53,978,103	$55,825,925	6.67%	$4,970,871	8.90%
29									
30				$175,825,925	$169,654,499	$175,825,925		$15,409,402	8.76%
31									
32	**Total**			3,441,812,925	3,211,545,284	3,345,017,639		259,455,424	7.76%

Sch. 25

PREFERRED STOCK

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value(a)	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	5% cumulative preferred	(b)	126,533	100.00	110.00	12,555,021	5.04%	12,653,300	637,617	5.08%
2	Serial preferred, cumulative:									
3	4.52% Series	11/55	2,065	100.00	103.50	196,824	4.74%	206,500	9,793	4.98%
4	7.00% Series	(c)	18,060	100.00	None	1,806,000	7.00%	1,806,000	126,420	7.00%
5	6.00% Series	(c)	5,932	100.00	None	593,200	6.00%	593,200	35,592	6.00%
6	5.00% Series	(c)	42,000	100.00	100.00	4,200,000	5.00%	4,200,000	210,000	5.00%
7	5.40% Series	(c)	65,960	100.00	101.00	6,596,000	5.40%	6,596,000	356,184	5.40%
8	4.72% Series	8/63	69,890	100.00	103.50	6,958,651	4.74%	6,989,000	331,320	4.76%
9	4.56% Series	2/65	84,592	100.00	102.34	8,410,129	4.59%	8,459,200	387,990	4.61%
10	8.92% Series	11/69	69,375	100.00	102.37	6,923,997	8.94%	6,937,500	620,032	8.95%
11	9.08% Series	6/71	164,893	100.00	104.02	16,440,752	9.11%	16,489,300	1,501,650	9.13%
12	7.96% Series	10/72	135,176	100.00	103.39	13,492,533	7.97%	13,517,600	1,078,000	7.99%
13										
14	No par serial preferred cumulative:									
15	$2.13 Series	5/77	666,210	25.00	25.54	15,992,249	8.87%	16,655,250	1,477,857	9.24%
16	$7.12 Series	3/87	440,000	100.00	104.75	43,443,230	7.21%	44,000,000	3,172,950	7.30%
17	$1.28 Series	9/60	381,220	25.00	26.35	9,530,500	5.12%	9,530,500	487,962	5.12%
18	$1.18 Series	5/62	420,116	25.00	26.15	10,502,900	4.72%	10,502,900	495,737	4.72%
19	$1.16 Series	8/64	193,102	25.00	26.11	4,827,550	4.64%	4,827,550	223,998	4.64%
20	$1.76 Series	3/68	393,868	25.00	25.96	9,846,700	7.04%	9,846,700	693,208	7.04%
21	$1.98 Series - 1971	3/71	501,998	25.00	26.21	12,549,950	7.92%	12,549,950	993,956	7.92%
22	$7.70 Series	8/91	1,000,000	100.00	N. A.	99,088,493	7.77%	100,000,000	7,770,832	7.84%
23	$1.98 Series - 1992	5/92	2,766,963	25.00	N. A.	65,021,691	8.43%	69,174,075	5,828,458	8.96%
24	$7.48 Series	6/92	750,000	100.00	N. A.	74,159,567	7.56%	75,000,000	5,673,577	7.65%
25	DARTS Series A	3/87	500	100,000.00	100,000.00	49,125,458	4.66%	50,000,000	2,328,223	4.74%
26	MAPS Series C	10/90	500	100,000.00	100,000.00	49,214,151	4.96%	50,000,000	2,478,962	5.04%
27										
28										
29										
30										
31										
32										
33	TOTAL		8,298,953			521,475,546		530,534,525	36,920,318	7.08%

(a) Par or Stated Value
(b) Replaced preferred stock issues sold in the 1920's and 1930's.
(c) Replaced an issue of The California Oregon Power Company as a result of merger with Pacific Power.

Sch. 26

COMMON STOCK

Line		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
1									
2									
3									
4	January	284,259,719	12.46	0.15			19.625	18.000	
5									
6	February	284,259,719	12.26	0.10			19.750	18.375	
7									
8	March	284,259,652	12.38	0.11	0.27	25.00%	19.500	18.250	13.1
9									
10	April	284,276,709	12.5	0.10			19.625	18.500	
11									
12	May	284,276,709	12.3	0.07			19.500	18.375	
13									
14	June	284,276,709	12.4	0.12	0.27	6.90%	19.875	18.125	16.4
15									
16	July	284,276,709	12.57	0.15			18.875	17.500	
17									
18	August	284,276,709	12.56	0.28			18.625	17.875	
19									
20	September	284,276,709	10.82	0.09	0.27	48.08%	19.500	17.875	9.0
21									
22	October	284,276,709	10.82	0.06			19.625	18.750	
23									
24	November	284,276,709	10.82	0.12			19.625	18.750	
25									
26	December	284,276,709	12.84	0.17	0.27	22.86%	21.625	19.625	14.7
27									
28									
29									
30									
31									
32	**TOTAL Year End**	284,272,466		1.52	1.08	28.95%	21.625	17.500	14.2

Sch. 27

MONTANA EARNED RATE OF RETURN

Line	Acct.	Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service	172,751,007	192,585,262	11.48%
3	108	(Less) Accumulated Depreciation	(53,631,725)	(59,869,358)	-11.63%
4		NET Plant in Service	119,119,282	132,715,904	11.41%
5					
6		**Additions**			
7	154, 156	Materials & Supplies	2,986,846	3,156,903	5.69%
8	165	Prepayments	600,152	537,515	-10.44%
9		Other Additions	7,203,536	7,825,849	8.64%
10		TOTAL Additions	10,790,534	11,520,267	6.76%
11					
12		**Deductions**			
13	190	Accumulated Deferred Income Taxes	(7,497,619)	(9,579,717)	-27.77%
14	252	Customer Advances for Construction	(14,232)	(37,481)	-163.36%
15	255	Accumulated Def. Investment Tax Credits	(664,121)	(556,848)	16.15%
16		Other Deductions	(535,987)	(1,233,066)	-130.06%
17		TOTAL Deductions	(8,711,959)	(11,407,112)	-30.94%
18		TOTAL Rate Base	121,197,857	132,829,059	9.60%
19					
20		Net Earnings	9,552,567	9,803,604	2.63%
21					
22		Rate of Return on Average Rate Base	7.88%	7.38%	-6.34%
23					
24		Rate of Return on Average Equity	8.38%	7.03%	-16.11%
25					
26		Major Normalizing Adjustments & Commission			
27		Ratemaking adjustments to Utility Operations			
28		Commission Ordered / Allowed Ratemaking Adjustments			
29		- Malin Midpoint Adj.	15,854	15,549	-1.92%
30		- Advertising Expense Adj.	2,472	1,303	-47.29%
31		- Present Rates Adj.	8,471	5,517	-34.87%
32		- Weather Normalization Adj.	110,296	81,838	-25.80%
33		- Production Cost Study Adj.	168,250	(619,821)	-468.39%
34		- Interest Expense Adj.	105,929	464,019	338.05%
35		- Bridger Coal Company	0	0	
36		- Miscellaneous Accounting Adj	(135,783)	(44,907)	66.93%
37		- Clean Air Credits	103,664	(35,166)	-133.92%
38		- Schedule M Adj	14,676	0	-100.00%
39		- Pension Expense	(88,080)	133,472	251.53%
40		- DSM Third Party Financing	(4,607)	(1,579)	65.73%
41		Other Company Ratemaking Adjustments			
42		- Other Adjustments	(364,166)	(159,315)	56.25%
43					
44					
45					
46					
47		Adjusted Rate of Return on Average Rate Base	7.68%	6.95%	-9.54%
48					
49		Adjusted Rate of Return on Average Equity	7.93%	5.80%	-26.86%

PACIFICORP
State of Montana - Electric Utility
Schedule 27 Detail for Other Rate Base Additions / Deductions

		Last Year	This Year
1	Rate Base:		
2	Plant Held for Future Use	98,562	115,331
3	Misc Deferred Debits	1,191,482	1,417,436
4	Acquisition Adjustment	2,577,310	2,611,239
5	Nuclear Fuel	0	0
6	Working Capital (1)	1,324,613	1,468,736
7	Weatherization Loans	1,310,168	1,481,375
8	Unrecovered Plant - Trojan	701,401	731,732
9	Total Other Additions	7,203,536	7,825,849
10			
11	Deductions:		
12	Accumulated Prov. - Trojan	(535,987)	(392,337)
13	Accumulated Prov. - Injuries	0	(130,368)
14	Accumulated Prov. - Proprety Ins	0	(73,756)
15	Other Deferred Credits	0	(636,605)
16	Total Other Deductions	(535,987)	(1,233,066)

(1) The Company does not have a specific Commission order authorizing the inclusion of cash working capital in rate base. However, cash working capital has been allowed in Company's previously authorized results (reference rate filings for Docket No. 87.12.80, Order No. 5326 and for Docket No. 89.6.17, Order No. 5432).

Sch. 28

MONTANA COMPOSITE STATISTICS

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	328,975
5	107	Construction Work in Progress	4,638
6	114	Plant Acquisition Adjustments	-
7	105	Plant Held for Future Use	-
8	154, 156	Materials & Supplies	585
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(94,427)
11	252	Contributions in Aid of Construction	(3,588)
12			
13		NET BOOK COSTS	236,183
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	47,111
18			
19	403 - 407	Depreciation & Amortization Expenses	5,345
20		Federal & State Income Taxes	2,647
21		Other Taxes	1,670
22		Other Operating Expenses	27,756
23		TOTAL Operating Expenses	37,418
24			
25		Net Operating Income	9,693
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	(111)
29			
30		NET INCOME	9,804
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	27,824
36		Commercial	5,172
37		Industrial	226
38		Other	43
39			
40		TOTAL NUMBER OF CUSTOMERS	33,265
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh)	12,038
45		Average Annual Residential Cost per (Kwh) (Cents) *	5.03
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	$50.46
48		Gross Plant per Customer	$9,890

Sch. 29

MONTANA CUSTOMER INFORMATION

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers (1)
1	Bigfork	N.A.	2,566	576	34	3,176
2	Columbia Falls	N.A.	2,931	521	41	3,493
3	Kalispell	N.A.	10,998	2,465	316	13,779
4	Kila	N.A.	257	41		298
5	Lakeside	N.A.	1,063	213	8	1,284
6	Libby	N.A.	4,383	957	68	5,408
7	Rollins	N.A.	288	47	4	339
8	Sommers	N.A.	608	113	8	729
9	Swan Lake	N.A.	186	29	1	216
10	Whitefish	N.A.	4,937	1,026	30	5,993
11						0
12						0
13	(1) Prepared with estimated numbers.					0
14						0
15						0
16						0
17						0
18						0
19						0
20						0
21						0
22						0
23						0
24						0
25						0
26						0
27						0
28						0
29						0
30						0
31						0
32	**TOTAL Montana Customers**	0	28,217	5,988	510	34,715

Sch. 30 **MONTANA EMPLOYEE COUNTS**

	Department	Year Beginning	Year End	Average
1	Big Fork	2	2	2
2	Facilities Engineering	1	1	1
3	Kalispell District	45	51	48
4	Kalispell Power	5	5	5
5	Libby District	10	9	10
6	Montana Area	7	2	5
7	Whitefish District	11	6	9
8				0
9				0
10				0
11				0
12				0
13				0
14				0
15				0
16				0
17				0
18				0
19				0
20				0
21				0
22				0
23				0
24				0
25				0
26				0
27				0
28				0
29				0
30				0
31				0
32				0
33				0
34				0
35				0
36				0
37				0
38				0
39				0
40				0
41				0
42				0
43				0
44				0
45				0
46				0
47				0
48				0
49				0
50	**TOTAL Montana Employees**	81	76	79

Sch. 31 **MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)**

	Project Description	Total Company	Total Montana
1	HERMISTON GENERATING PROJECT	173,612	3,086
2	FOOTE CREEK WIND PROJECT (WYOMING)	43,192	768
3	COLUMBIA HILLS WIND FARM	22,882	407
4	NEW CSS SYSTEM	13,239	325
5	JAMES RIVER CAMAS COGENERATION	12,199	217
6	BUSINESS CENTER DEVELOPMENT	7,776	145
7	HUNTINGTON UNIT 1 TURBINE UPGRADE	5,614	100
8	DAVE JOHNSTON MINE - (1) SHOVEL	3,017	54
9	N UMPQUA RELICENSING	2,667	82
10	COTTONWOOD MINE - HIGH VOLTAGE	2,595	46
11	YALE RELICENSING	1,959	60
12	JIM BRIDGER #2 TURBINE UPGRADE	1,869	33
13	PROSPECT 3 DIVERSION DAM, FISH SCREENS	1,843	57
14	BUTLERVILLE 138/46 KV SUBSTATION	1,833	33
15	COPCO 1 MAJOR OVERHAUL/NEW RUNNERS	1,828	56
16	C-UST UST REPLACE	1,812	34
17	JIM BRIDGER: U3 CONDENSER TITANIUM RETUBE	1,720	31
18	YALE RUNNERS UPGRADE	1,620	50
19	JIM BRIDGER #3 TURBINE UPGRADE	1,524	27
20	NAUGHTON: WATER TREATMENT SYSTEM	1,431	25
21	MEDFORD - LINE 79 CONVERSION PROJECT	1,419	25
22	PORTLAND - CLARK COUNTY PUD INTERTIE	1,335	24
23	POWER SYSTEMS ALTERNATE CONTROL CENTER	1,311	24
24	WYODAK - REPLACE GENERATOR STEP-UP TRANSFORM	1,252	22
25	ACCOUNTING SYSTEMS 1996 ENHANCEMENTS	1,250	23
26	NETWORK ENHANCEMENT (PPW-PAC)	1,159	22
27	DAVE JOHNSTON MINE - PURCHASE 1 FRONT END LOAD	1,150	21
28	AUTOCAD MAPPING	1,071	20
29	NAU: BOILER REPLACEMENTS	1,047	19
30	ALL OTHER	397,005	N/A
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50	TOTAL	712,231	5,836

Sch. 32 TOTAL SYSTEM & MONTANA PEAK AND ENERGY

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	4	08:00	7,391	5,467,472	996,244
2	Feb.	13	09:00	7,134	4,708,252	927,392
3	Mar.	6	08:00	6,990	5,192,455	1,042,254
4	Apr.	19	08:00	6,506	4,744,241	922,325
5	May	31	14:00	6,094	4,783,878	995,285
6	Jun.	26	15:00	6,656	4,733,672	1,010,945
7	Jul.	28	15:00	7,222	5,441,290	1,220,162
8	Aug.	3	15:00	7,070	5,676,070	1,389,792
9	Sep.	1	14:00	6,709	5,279,265	1,413,767
10	Oct.	31	08:00	6,605	5,862,138	1,890,374
11	Nov.	2	08:00	7,099	5,774,042	1,666,752
12	Dec.	18	18:00	7,289	6,072,075	1,613,231
13	TOTAL				63,734,850	15,088,523

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.	5	10:00	171	107,289	17,720
15	Feb.	13	10:00	161	93,579	16,495
16	Mar.	2	08:00	149	99,112	18,539
17	Apr.	10	10:00	124	85,189	16,405
18	May	26	09:00	113	82,841	17,703
19	Jun.	7	10:00	116	78,846	17,982
20	Jul.	24	12:00	108	85,097	21,703
21	Aug.	15	11:00	110	91,153	24,720
22	Sep.	22	09:00	120	92,727	25,147
23	Oct.	30	08:00	141	111,389	33,624
24	Nov.	2	08:00	156	114,083	29,646
25	Dec.	8	09:00	176	127,805	28,695
26	TOTAL				1,169,110	268,379

Sch. 33 TOTAL SYSTEM Sources & Disposition of Energy

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	48,004,952	Sales to Ultimate Consumers	
3	Nuclear	(627)	(Include Interdepartmental)	43,167,562
4	Hydro - Conventional	4,612,593		
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	81,285	for Resale	1,287,297
7	(Less) Energy for Pumping			
8	**NET Generation**	52,698,203	Non-Requirements Sales	
9	Purchases	11,203,874	for Resale	15,088,523
10	Power Exchanges			
11	Received	14,008,423	Energy Furnished	
12	Delivered	13,884,259	Without Charge	
13	**NET Exchanges**	124,164		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	9,108,145	Electric Utility	80,962
16	Delivered	9,108,145		
17	**NET Transmission Wheeling**	0	Total Energy Losses	4,110,506
18	Transmission by Others Losses	(291,391)		
19	**TOTAL**	63,734,850	**TOTAL**	63,734,850

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Cholla Unit No. 4	Joseph City, Arizona	383.0	1,695,707
2	Thermal	Craig Units #1 & #2	Craig, Colorado	165.0	1,264,464
3	Thermal	Hayden Plant	Hayden, Colorado	78.0	611,330
4	Thermal	Colstrip Unit #3 & #	Colstrip, Montana	168.0	994,561
5	Thermal	Carbon Plant	Castle Gate, Utah	183.0	1,352,883
6	Thermal	Gadsby Plant	Salt Lake City, Utah	235.0	637,451
7	Thermal	Hunter Plant	Castle Dale, Utah	1,074.0	8,324,268
8	Thermal	Huntington Plant	Huntington, Utah	579.0	6,810,471
9	Thermal	Centralia Plant	Centralia, Washington	639.0	3,069,611
10	Thermal	Dave Johnston Plant	Glenrock, Wyoming	798.0	5,956,956
11	Thermal	Jim Bridger Plant	Rock Springs, Wyoming	1,628.0	10,367,115
12	Thermal	Wyodak Plant	Gillette, Wyoming	318.0	2,008,284
13	Thermal	Naughton Plant	Kemmerer, Wyoming	716.0	4,772,109
14	Geothermal	Blundell Plant	Milford, Utah	24.0	139,742
15	Combustion Turbine	Little Moutain Plant	Ogden, Utah	18.0	81,285
16	Nuclear	Trojan Plant	Rainier, Oregon		(627)
17	Hydro	Copco #1	Copco, California	27.0	95,226
18	Hydro	Copco #2	Copco, California	31.0	121,405
19	Hydro	Fall Creek	Copco, California	3.0	11,768
20	Hydro	Iron Gate	Hornbrook, California	21.0	113,571
21	Hydro	Ashton	Ashton, Idaho	7.0	42,801
22	Hydro	Cove	Grace, Idaho	7.0	17,425
23	Hydro	Grace	Grace, Idaho	32.0	90,046
24	Hydro	Last Chance	Grace, Idaho	1.0	4,779
25	Hydro	Oneida	Preston, Idaho	25.0	36,325
26	Hydro	Paris	Paris, Idaho	1.0	2,488
27	Hydro	Soda	Soda, Idaho	7.0	15,090
28	Hydro	St. Anthony	St. Anthony, Idaho	1.0	2,211
29	Hydro	Bigfork	Bigfork, Montana	5.0	13,699
30	Hydro	Bend	Bend, Oregon	1.0	3,798
31	Hydro	Clearwater #1	Toketee Falls, Oregon	15.0	54,972
32	Hydro	Clearwater #2	Toketee Falls, Oregon	24.0	68,358
33	Hydro	Cline Falls	Redmond, Oregon	1.0	3,237
34	Hydro	Eagle Point	Eagle Point, Oregon	3.0	15,133
35	Hydro	East Side	Klamath Falls, Oregon	4.0	15,185
36	Hydro	Fish Creek	Toketee Falls, Oregon	13.0	72,346
37	Hydro	John C. Boyle	Keno, Oregon	92.0	286,613
38	Hydro	Lemolo #1	Toketee Falls, Oregon	30.0	133,811
39	Hydro	Lemolo #2	Toketee Falls, Oregon	35.0	189,378
40	Hydro	Powerdale	Hood River, Oregon	6.0	38,211
41	Hydro	Prospect #1	Prospect, Oregon	4.0	17,867
42	Hydro	Prospect #2	Prospect, Oregon	36.0	265,193
43	Hydro	Prospect #3	Prospect, Oregon	8.0	42,012
44	Hydro	Prospect #4	Prospect, Oregon	1.0	3,398
45	Hydro	Slide Creek	Toketee Falls, Oregon	18.0	102,695
46	Hydro	Soda Springs	Toketee Falls, Oregon	12.0	72,375
47	Hydro	Stayton	Stayton, Oregon		
48	Hydro	Toketee	Toketee Falls, Oregon	45.0	247,769
49	Hydro	Wallowa Falls	Joseph, Oregon	1.0	2,219

SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
50	Hydro	West Side	Klamath Falls, Oregon	1.0	3,292
51	Hydro	American Fork	Plesant Grove, Utah		
52	Hydro	Beaver - Upper	Beaver, Utah	2.0	12,216
53	Hydro	Cutler	Collinston, Utah	30.0	89,085
54	Hydro	Fountain Green	Fountain Green, Utah	0.0	1,392
55	Hydro	Granite	Salt Lake City, Utah	1.0	7,026
56	Hydro	Gunlock	Gunlock, Utah	1.0	2,474
57	Hydro	Olmsted	Orem, Utah	8.0	27,938
58	Hydro	Pioneer	Ogden, Utah	5.0	21,865
59	Hydro	Sand Cove	Sand Cove, Utah	1.0	2,151
60	Hydro	Snake Creek	Midway, Utah	1.0	3,823
61	Hydro	Stairs	Salt Lake City, Utah	1.0	5,753
62	Hydro	Veyo	Veyo, Utah	0.0	1,069
63	Hydro	Weber	Uintah, Utah	3.0	19,624
64	Hydro	Condit	Underwood, Washington	16.0	100,787
65	Hydro	Drop	Naches, Washington	1.0	7,307
66	Hydro	Merwin	Ariel, Washington	147.0	589,575
67	Hydro	Naches	Naches, Washington	6.0	23,519
68	Hydro	Swift #1	Cougar, Washington	262.0	859,960
69	Hydro	Yale	Amboy, Washington	142.0	631,402
70	Hydro	Viva Naughton	Kemmerer, Wyoming	1.0	2,406
71	Pumping	Lifton	Lifton, Idaho		(1,475)
72					
73		Total Net Generation		8,152.0	52,698,203
74					
75					
76	POWER PURCHASES - ACCOUNT 555				
77					
78	Anaheim, City of		(1)		3,338
79	Arizona Public Service Company		(1)		7,356
80	Associated Power Services		(1)		23,800
81	BC Hydro		(1)		5,050
82	Beaver City		(2)		64
83	Bell Mountain Power		02-Jan-2020		1,713
84	Biomass One, Limited Partnership		31-Jan-2010		174,995
85	Birch Creek Hydro		21-Aug-2019		14,417
86	Black Hills Power & Light Company		30-Jun-2012		99
87	Black Hills Power & Light Company		31-Dec-2000		39,165
88	Blanding City		(2)		1,636
89	Bogus Creek		31-Dec-2017		1,252
90	Boise Cascade Corporation		(1)		34
91	Bonneville Power Administration		31-Aug-2011		
92	Bonneville Power Administration		31-Mar-2003		
93	Bonneville Power Administration		30-Jun-95		547,400
94	Bonneville Power Administration		(1)		1,475,531
95	Boston Power		31-Dec-2004		414
96	Boyd, James		31-Dec-2003		2,655
97	Buffalo Hydro Inc.		08-Aug-2014		1,874
98	CDM Hydro		04-Dec-2019		36,694

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SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
99	California Dept. of Water Resources		(1)		142,269
100	California Dept. of Water Resources		31-Jan-96		292,900
101	Central Oregon Irrigation District		31-Dec-2018		15,356
102	Chelan County Public Utility Dist. No. 1		31-Aug-2018		320,490
103	Chelan County Public Utility Dist. No. 1		(1)		66,670
104	Colockum Transmission Company		(1)		1,072
105	Colorado Public Service Company		(1)		4,570
106	Columbia Storage Power Exchange		31-Mar-2003		228,761
107	Commercial Energy Management		31-Mar-2020		1,812
108	Cook Electric		31-Dec-2017		10,768
109	Cowlitz County Public Utility Dist. No. 1		(1)		430
110	Curtiss Livestock		31-Dec-98		156
111	Davis County Waste Management		(3)		3,110
112	Deseret Generation & Trans. Coop.		31-Dec-97		507,473
113	Deseret Generation & Trans. Coop.		(1)		51,546
114	Difani, Chris		30-Apr-2007		19
115	Douglas County Public Utility Dist. No. 1		31-Aug-2018		292,604
116	Douglas County Public Utility Dist. No. 1		(1)		48,893
117	DR Johnson Lumber Company		31-Dec-2006		63,065
118	Eagle Point		31-Dec-2021		3,178
119	El Paso Electric Company		(1)		1,015
120	Electric Clearinghouse		(1)		18,190
121	Enron Power Marketing, Inc.		(1)		2,215
122	Eugene Water & Electric Board		(1)		21,356
123	Falls Creek		31-Dec-2019		19,114
124	Farmers Irrigation #2		31-Dec-2010		24,450
125	Fery, Lloyd		31-Dec-98		243
126	Fillmore City		(2)		84
127	Fox, Marion		(5)		2
128	Galesville Dam		31-Dec-2021		6,571
129	Garland Canal		31-Dec-2014		10,200
130	General Chemical Company		(1)		11,214
131	Georgetown Power		02-Jul-2019		2,170
132	Grand Valley Rural Power Lines		(2)		107
133	Grant County Public Utility Dist. No. 2		(4)		87,600
134	Grant County Public Utility Dist. No. 2		31-Oct-2005		625,697
135	Grant County Public Utility Dist. No. 2		31-Oct-2005		898,467
136	Grant County Public Utility Dist. No. 2		(1)		243,374
137	Heber Light & Power		(2)		677
138	Idaho Falls, City of		02-Nov-2023		40,822
139	Idaho Power Company		(1)		191,552
140	Ingram Warm Springs Ranch		31-May-2021		3,669
141	Intermountain Power Project		(1)		7,910
142	Intermountain Power Project		15-Jun-2027		215,245
143	James River		(1)		31,032
144	Kennecott		(1)		908
145	Koch Power Services		(1)		25
146	LG&E Power		(1)		3,268
147	Lacomb Hydro		31-Dec-2018		3,635

	Type	Name	Location	Peak (MW)	Energy (Mwh)
148	Lake Siskiyou		31-Dec-2020		26,713
149	Los Alamos, City of		(1)		30
150	Los Angeles, City of		(1)		24,034
151	Louis Dreyfus		(1)		14,135
152	Luckey, Paul		31-Dec-2013		323
153	Marsh Valley Hydro Electric Company		10-Mar-2028		5,665
154	Middlefork Irrigation District		31-Dec-2004		24,962
155	Mink Creek Hydro		31-Dec-2021		9,169
156	Montana Power Company		31-Dec-95		87,600
157	Montana Power Company		(1)		60,180
158	Montana Power Company		31-Mar-96		73,200
159	Morgan City		(2)		19
160	Mountain Energy		31-Dec-2004		136
161	Murray City		(2)		378
162	Nephi City		(2)		17
163	Nevada Power Company		(1)		250
164	New Mexico Public Service Company		(1)		25,810
165	Nicholson Sunnybar Ranch		27-Jun-2020		3,141
166	North Fork Sprague		31-Dec-2023		3,269
167	Northern California Power Agency		(1)		11,862
168	Odell Creek		31-Dec-2010		292
169	Opal Springs		31-Dec-2020		30,762
170	Ormsby, Leslie		31-Dec-93		18
171	O.J. Power Company		04-Mar-2021		831
172	Pacific Gas & Electric Company		(1)		337,043
173	Pancheri, Inc.		01-Mar-2013		130
174	Plains Electric		(1)		6,245
175	Plains Electric		28-Nov-95		269,040
176	Portland General Electric Company		18-Dec-2001		23,976
177	Portland General Electric Company		(1)		13,095
178	Preston City Hydro		24-Feb-2017		3,275
179	Provo City		(2)		147
180	Puget Sound Power & Light Company		(1)		464,147
181	Redding, City of		31-May-2014		33,480
182	Riverside, City of		(1)		1,407
183	Rocky Mountain Generation Cooperative		(1)		71,340
184	Rousch, Neil		31-Dec-98		444
185	Royal Oak		Dec-93		
186	SF Phosphates Limited		(1)		1,319
187	Sacramento Municipal Utility District		(1)		22,262
188	Salt River Project		(1)		18,268
189	Salt River Project		31-Dec-98		172,440
190	San Diego Gas & Electric Company		(1)		4,500
191	Santa Clara, City of		(1)		320
192	Santiam Water Control District		31-Dec-2019		1,501
193	Seattle City Light		(1)		24,797
194	Sierra Pacific Power Company		(1)		3,124
195	Slate Creek		31-Dec-2018		14,400
196	Snohomish Public Utility District		(1)		1,800

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SOURCES OF ELECTRIC SUPPLY

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
197	Southern California Edison Company		(1)		25,121
198	Southern California Edison Company		15-Mar-2003		
199	Southwestern Public Service Company		(1)		2,135
200	Spanish Fork City		(2)		47
201	Springville City		(2)		43
202	Stauffer Dry Creek		15-Dec-2022		11,940
203	Stimson Lumber		21-Apr-95		3,348
204	Strawberry Electric Service District		(1)		68
205	Sunnyside Cogeneration Associates		03-Feb-2023		311,472
206	Tacoma City Light		(1)		8,568
207	Teton Generation Station		02-Feb-2020		219
208	Thayne Ranch Hydro		31-Dec-2015		2,192
209	TKO		01-Jan-2013		187
210	Tri-State Generation & Transmission		31-Dec-2020		669,253
211	Tucson Electric Power Company		(1)		11,146
212	Turlock Irrigation District		(1)		8,809
213	United States Bureau of Reclamation		06-Oct-2000		45,527
214	United States Bureau of Reclamation		(1)		11,658
215	Utah Assoc. Municipal Power Systems		(1)		302
216	Utah Municipal Power Agency		(1)		1,002
217	Walla Walla, City of		31-Dec-2012		15,619
218	Warm Springs Forest Products Industry		(1)		376
219	Warm Springs Power Enterprises		31-Dec-2001		62,954
220	Washington Public Power Supply System		30-Jun-96		576,326
221	Washington Water Power Company		31-Dec-97		438,000
222	Washington Water Power Company		15-Sep-2003		55,200
223	Washington Water Power Company		(6)		9,534
224	Washington Water Power Company		(1)		162,695
225	Western Area Power Administration		(1)		8,313
226	White, J.E.		31-Dec-94		59
227	Whitmore Oxygen		(1)		1,681
228	Whitney, A.C.		31-Dec-93		1
229	Wiggins, Duane		31-Dec-98		48
230	Yakima Tieton		31-Dec-2005		6,666
231					
232					
233					
234	System Deviation				(1,372)
235					
236	Total Purchases				11,203,874
237					
238					
239	Net Exchanges				124,164
240					
241					
242	Transmission by Others Losses				(291,391)
243					
244					
245	Total Sources				63,734,850
246					

SOURCES OF ELECTRIC SUPPLY

Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)

Notes:
(1) Non-firm.
(2) Under electric service agreement subject to termination upon timely notification.
(3) 6 month renewal unless given 30 days notice to terminate.
(4) Grant County PUD No. 2 - Contract Termination Date: Upon 2 years written notice.
(5) Until terminated with 1 year written notice.
(6) Prior period adjustment.

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Carbon 1						
1.	02/01/95 12:20	-	02/03/95 01:33	Unplanned	37.22	2,605.17
	Descr: Unit off line to repair high temperature superheat tube leak (travelle					
2.	04/07/95 20:39	-	05/01/95 04:48	Planned	560.15	39,210.50
	Descr: Unit off line for overhaul					
3.	05/01/95 11:58	-	05/01/95 13:25	Unplanned	1.45	101.50
	Descr: Unit trip - the unit was at 45 mw net and the governor would not open					
4.	05/01/95 20:45	-	05/02/95 22:27	Unplanned	25.70	1,799.00
	Descr: The unit was resticted to 45 mw net due to 1-2 circ pump being out of					
5.	05/08/95 02:03	-	05/08/95 17:29	Unplanned	15.43	1,080.33
	Descr: The unit was taken off line to replace 1-1 circ pump expansion joint					
6.	07/20/95 19:22	-	07/20/95 20:55	Unplanned	1.55	108.50
	Descr: Cro was attempting to increase superheat outlet pressure setpoint.					
7.	08/01/95 09:32	-	08/01/95 10:42	Unplanned	1.17	81.67
	Descr: Relay technicians wire checking to get panels ready to move controls t					
8.	10/02/95 13:47	-	10/02/95 15:05	Unplanned	1.30	91.00
	Descr: Unit trip - high furnace draft (see incident reprot #c1-95-15). an					
9.	11/16/95 11:44	-	11/16/95 15:44	Unplanned	4.00	280.00
	Descr: Unit was taken off line for installation of new max 1 control system					
	*** **Unit Summary for Carbon 1 for the year 1995 =**				647.97	45,357.67
Carbon 2						
1.	02/05/95 23:40	-	02/08/95 04:37	Unplanned	52.95	5,559.75
	Descr: Unit taken off line to clear pluggage in the high temperature superhea					
2.	04/08/95 03:37	-	04/09/95 01:40	Unplanned	22.05	2,315.25
	Descr: Er. unit was taken off line during unit 1 overhaul so that the potent					
3.	05/12/95 23:48	-	05/14/95 11:25	Unplanned	17.82	1,870.75
	Descr: Unit was taken off line to clean the economizer and to clean the conde					
4.	05/12/95 23:48	-	05/14/95 11:25	Unplanned	17.81	1,869.88
	Descr: The unit was taken off line to clean the condenser and the economizer					
5.	05/17/95 23:28	-	05/19/95 20:55	Unplanned	45.45	4,772.25
	Descr: Unit was taken off line to inspect 2-1 circ. water pump and to isolate					
6.	06/07/95 22:16	-	06/08/95 11:30	Unplanned	13.23	1,389.50
	Descr: Unit was taken off line to change the impellar on 2-1 circ pump					
7.	06/11/95 14:00	-	06/11/95 19:00	Unplanned	5.00	525.00
	Descr: The unit had been off line to first change the impellar on 2-1 circ					
8.	06/28/95 22:38	-	06/29/95 15:40	Unplanned	17.03	1,788.50
	Descr: The unit was taken off line to inspect 2-1 circ pump (high vibration -					
9.	07/10/95 15:15	-	07/10/95 19:10	Unplanned	3.92	411.25
	Descr: 2-1 condensate pump breaker went to groung and caused 2-1 coal mill					
10.	07/15/95 00:30	-	07/16/95 04:19	Unplanned	27.82	2,920.75
	Descr: Unit was taken off line to replace 2-1 circ pump impellar					
11.	08/06/95 03:19	-	08/08/95 00:53	Unplanned	45.57	4,784.50
	Descr: High temperature superheat tube leak (sootblower erosion)					
12.	10/23/95 11:57	-	10/23/95 13:18	Unplanned	1.35	141.75
	Descr: Unit trip - relay dept. working oncircuit breakers (see incident repor					
	*** **Unit Summary for Carbon 2 for the year 1995 =**				270.00	28,349.13

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Centralia 1						
1.	01/01/95 00:47	-	01/01/95 09:06	Unplanned	8.32	5,572.17
	Descr: E-h leak repair					
2.	06/05/95 04:25	-	06/05/95 17:53	Unplanned	13.47	9,022.67
	Descr: Unit tripped on diff. expansion, main turbine, hp turbine outer casing					
3.	06/05/95 17:53	-	06/05/95 20:27	Unplanned	2.57	1,719.67
	Descr: Control valve problems					
	*** * * Unit Summary for Centralia 1 for the year 1995 =**				24.36	16,314.51
Centralia 2						
1.	01/22/95 15:51	-	01/22/95 20:15	Unplanned	4.40	2,948.00
	Descr: Aux boiler trip on low drum level					
2.	01/22/95 20:15	-	01/22/95 22:44	Unplanned	2.48	1,663.83
	Descr: Ignitor oil gun not proving					
3.	02/12/95 03:07	-	02/12/95 04:47	Unplanned	1.67	1,116.67
	Descr: Flame scanner unable to detect flame at low load					
4.	02/17/95 14:00	-	02/17/95 15:12	Unplanned	1.20	804.00
	Descr: Loss of bcp seal differential pressure					
5.	03/04/95 12:01	-	03/04/95 13:31	Unplanned	1.50	1,005.00
	Descr: Aux boiler tripping					
6.	03/04/95 13:31	-	03/05/95 01:31	Unplanned	12.00	8,040.00
	Descr: #21 feedwater heater repairs					
7.	03/05/95 01:31	-	03/05/95 08:01	Unplanned	6.50	4,355.00
	Descr: Generator breaker 4536 logic					
8.	03/05/95 08:01	-	03/05/95 11:01	Unplanned	3.00	2,010.00
	Descr: Burner control relay					
9.	03/21/95 08:56	-	03/21/95 14:22	Unplanned	4.77	3,193.67
	Descr: Id fans ran back causing furnace high pressure condition.					
10.	03/31/95 16:50	-	06/17/95 00:00	Planned	1,854.17	1,242,291.67
	Descr: Annual overhaul					
11.	07/04/95 10:58	-	07/04/95 14:58	Planned	4.00	2,680.00
	Descr: Turbine performance testing					
12.	07/04/95 14:58	-	07/04/95 18:58	Unplanned	4.00	2,680.00
	Descr: Ignitors					
13.	07/04/95 18:58	-	07/04/95 22:58	Unplanned	4.00	2,680.00
	Descr: Burner control relay					
14.	07/04/95 22:58	-	07/04/95 23:58	Unplanned	1.00	670.00
	Descr: Auxiliary bus breaker failure					
15.	07/04/95 23:58	-	07/05/95 02:58	Unplanned	3.00	2,010.00
	Descr: Exciter field breaker					
16.	10/11/95 18:07	-	10/14/95 18:04	Unplanned	71.95	48,206.50
	Descr: Economizer tube leak					
17.	11/11/95 13:00	-	11/18/95 06:43	Unplanned	161.72	108,350.17
	Descr: North throat bridged - slag					
18.	11/18/95 06:43	-	11/18/95 22:48	Unplanned	16.08	10,775.83
	Descr: Oil leak on #2 main turbine trip block					
19.	12/02/95 00:15	-	12/03/95 08:15	Unplanned	32.00	21,440.00
	Descr: Boiler tube leak bottom side west slope tubes					
20.	12/03/95 08:15	-	12/03/95 11:15	Unplanned	3.00	2,010.00
	Descr: Aux air burner buckets link broken					
21.	12/03/95 11:15	-	12/03/95 12:45	Unplanned	1.50	1,005.00
	Descr: #21 fd fan ema motor to gearbox transition casting broken					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time - Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Centralia 2				
22.	12/03/95 12:45 - 12/03/95 14:05	Unplanned	1.33	893.33
	Descr: Turbine front standard test problems			
	*** * * Unit Summary for Centralia 2 for the year 1995 =**		2,195.27	1,470,828.67
Dave Johnston 1				
1.	01/27/95 14:32 - 01/27/95 15:43	Unplanned	1.18	125.43
	Descr: Mft hi drum lvl (ctls)			
2.	03/23/95 01:30 - 03/25/95 07:18	Unplanned	53.80	5,702.80
	Descr: Primary sh tube leak repair			
3.	04/02/95 00:49 - 04/02/95 09:10	Unplanned	7.35	779.10
	Descr: Rh stop vlv oil leak			
4.	04/02/95 09:10 - 04/02/95 13:09	Unplanned	3.98	422.23
	Descr: Ignitor failure & repair			
5.	04/02/95 15:43 - 04/02/95 17:55	Unplanned	2.20	233.20
	Descr: Furnace draft problems			
6.	04/14/95 14:06 - 04/14/95 16:14	Unplanned	2.13	226.13
	Descr: Mft/drum lvl low/fd wtr reg vlv ctl			
7.	04/20/95 22:54 - 04/21/95 15:58	Unplanned	17.07	1,809.07
	Descr: Drum safety vlv repair			
8.	06/17/95 00:03 - 06/18/95 06:20	Unplanned	30.28	3,210.03
	Descr: Wash & clean plugged air htr baskets			
9.	08/26/95 00:03 - 08/30/95 09:28	Unplanned	105.42	11,174.17
	Descr: Tube leak - ssh			
10.	09/29/95 13:17 - 09/29/95 14:18	Unplanned	1.02	107.77
	Descr: Mft - low drum level trip			
	*** * * Unit Summary for Dave Johnston 1 for the year 1995 =**		224.43	23,789.93
Dave Johnston 2				
1.	03/10/95 18:46 - 03/11/95 12:05	Unplanned	17.32	1,835.57
	Descr: Economizer tube leak & repair			
2.	03/11/95 07:38 - 03/12/95 14:03	Unplanned	25.97	2,752.47
	Descr: Repair main steam safety			
3.	03/14/95 00:25 - 03/15/95 03:08	Unplanned	26.72	2,831.97
	Descr: Reheat tube leak & repair			
4.	07/15/95 23:26 - 07/16/95 18:30	Unplanned	19.07	2,021.07
	Descr: Repair main steam safety vlv			
5.	08/09/95 08:15 - 08/09/95 09:18	Unplanned	1.05	111.30
	Descr: Swapped station service fds			
6.	08/28/95 10:04 - 08/30/95 21:03	Unplanned	58.98	6,252.23
	Descr: Tube leaks - ssh			
7.	09/23/95 23:48 - 09/24/95 13:47	Unplanned	13.98	1,482.23
	Descr: Safety repair to start up			
8.	10/13/95 10:09 - 10/13/95 15:05	Unplanned	4.93	522.93
	Descr: Mft - lost 'a' 480v buss			
9.	11/29/95 01:25 - 11/30/95 21:27	Unplanned	44.03	4,667.53
	Descr: Ww tube leak			
	*** * * Unit Summary for Dave Johnston 2 for the year 1995 =**		212.05	22,477.30

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Dave Johnston 3						
1.	01/29/95 00:59	-	01/30/95 03:27	Unplanned	26.47	6,087.33
	Descr: Air leak cant hold vac					
2.	03/16/95 06:04	-	03/16/95 15:31	Unplanned	9.45	2,173.50
	Descr: Generator ctl and meter'g devices defective also cet's conducted inspe					
3.	04/01/95 17:49	-	04/07/95 02:52	Unplanned	128.05	29,451.50
	Descr: Hopper filled w/ slag & molten lava					
4.	04/07/95 03:00	-	04/07/95 04:54	Unplanned	1.90	437.00
	Descr: Mft - high drum level					
5.	07/21/95 23:45	-	07/25/95 04:03	Unplanned	76.30	17,549.00
	Descr: Remove clinkers					
6.	07/25/95 04:58	-	07/25/95 08:52	Unplanned	3.90	897.00
	Descr: Feed wtr reg vlv bypass					
7.	08/07/95 22:09	-	08/08/95 00:10	Unplanned	2.02	463.83
	Descr: Hi drum lost 3b mill					
8.	09/12/95 11:00	-	09/12/95 12:10	Unplanned	1.17	268.33
	Descr: Loss of circ water (pond)					
9.	11/03/95 22:30	-	11/05/95 02:47	Unplanned	28.28	6,505.17
	Descr: Unit off - safety and other repairs					
10.	11/22/95 22:07	-	11/23/95 19:22	Unplanned	21.25	4,887.50
	Descr: Tube leak repair					
11.	12/19/95 09:52	-	01/01/96 00:00	Unplanned	302.13	69,490.67
	Descr: Actual cause unknown at time of report will update when final report i					
	* * * Unit Summary for Dave Johnston 3 for the year 1995 =				600.92	138,210.83
Dave Johnston 4						
1.	03/11/95 13:20	-	03/12/95 13:04	Unplanned	23.73	7,832.00
	Descr: 4a pa fan motor grounded					
2.	06/03/95 00:03	-	07/05/95 16:49	Planned	784.77	258,973.00
	Descr: Unit/boiler/scrubber overhaul					
3.	07/08/95 00:45	-	07/08/95 21:35	Unplanned	20.83	6,875.00
	Descr: Repair (2) tube leaks					
4.	08/28/95 04:15	-	09/10/95 23:31	Unplanned	331.27	109,318.00
	Descr: Boiler implosion - damaged frontwall tube attachments					
5.	09/21/95 11:23	-	09/22/95 10:35	Unplanned	23.20	7,656.00
	Descr: mft - draft, 3b crusher mtr smoked b buss trip					
6.	10/11/95 07:41	-	10/11/95 08:58	Unplanned	1.28	423.50
	Descr: Mft combustion controls					
7.	10/11/95 09:16	-	10/11/95 14:37	Unplanned	5.35	1,765.50
	Descr: Mft warm up oil pressure reg.					
8.	12/21/95 12:56	-	12/22/95 16:48	Unplanned	27.87	9,196.00
	Descr: Repair ww & dc tube leaks					
	* * * Unit Summary for Dave Johnston 4 for the year 1995 =				1,218.30	402,039.00
Hunter 1						
1.	01/16/95 12:07	-	01/18/95 00:00	Unplanned	35.88	14,891.58
	Descr: Boiler tube leak (reheat section)					
2.	01/18/95 00:00	-	01/18/95 15:00	Unplanned	15.00	6,225.00
	Descr: Oil guns won't go into service					
3.	01/18/95 15:00	-	01/18/95 22:10	Unplanned	7.17	2,974.17
	Descr: Boiler tube leak (waterwall)					
4.	01/18/95 22:10	-	01/19/95 10:30	Unplanned	12.33	5,118.33
	Descr: Unit inefficiency (temps, press, etc.)					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time - Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Hunter 1				
5.	01/26/95 22:30 - 01/27/95 01:17	Unplanned	2.78	1,155.08
	Descr: Oil guns won't go in service			
6.	01/30/95 14:13 - 01/31/95 06:50	Unplanned	16.62	6,895.92
	Descr: Boiler tube leak (waterwall)			
7.	01/31/95 08:20 - 01/31/95 12:30	Unplanned	4.17	1,729.17
	Descr: Waiting on switchyard problems			
8.	02/03/95 23:30 - 02/05/95 02:21	Unplanned	26.85	11,142.75
	Descr: Boiler tube leak (waterwall)			
9.	03/23/95 11:20 - 03/27/95 01:45	Unplanned	86.42	35,862.92
	Descr: Boiler tube leak (first superheat)			
10.	03/27/95 01:45 - 03/27/95 15:46	Unplanned	14.02	5,816.92
	Descr: Start-up in progress			
11.	03/30/95 12:00 - 03/31/95 14:25	Unplanned	26.42	10,962.92
	Descr: Boiler tube leak (first superheat)			
12.	04/21/95 22:29 - 05/20/95 04:07	Planned	677.63	281,217.83
	Descr: Unit overhaul (boiler)			
13.	05/20/95 05:40 - 05/20/95 09:43	Unplanned	4.05	1,680.75
	Descr: Low drum level trip			
14.	05/20/95 14:23 - 05/20/95 15:24	Unplanned	1.02	421.92
	Descr: Overspeed trip testing			
15.	05/22/95 00:06 - 05/22/95 07:48	Unplanned	7.70	3,195.50
	Descr: Unit off line - lost 1-2 load center			
16.	06/05/95 18:35 - 06/05/95 20:19	Unplanned	1.73	719.33
	Descr: Unit trip - lost both bfpt's			
17.	06/09/95 02:55 - 06/09/95 20:00	Unplanned	17.08	7,089.58
	Descr: Unit trip - switchyard problems			
18.	07/09/95 01:12 - 07/09/95 10:07	Unplanned	8.92	3,700.42
	Descr: Off line to repair bfpts			
19.	07/09/95 10:35 - 07/09/95 11:40	Unplanned	1.08	449.58
	Descr: Unit off line to repair bfpts			
20.	07/16/95 11:59 - 07/16/95 15:40	Unplanned	3.68	1,528.58
	Descr: Low drum level trip, lost 1-2 bfpt			
21.	07/17/95 08:08 - 07/17/95 11:33	Unplanned	3.42	1,417.92
	Descr: Unit trip, lost 1-2 bfpt			
22.	08/16/95 14:40 - 08/16/95 20:30	Unplanned	5.83	2,420.83
	Descr: Unit off bfpts-low vacuum trip			
23.	08/31/95 16:51 - 09/02/95 02:29	Unplanned	33.63	13,957.83
	Descr: Off line - da crack repair			
24.	09/02/95 22:19 - 09/03/95 08:28	Unplanned	10.15	4,212.25
	Descr: Unit off line - scrubber booster fan damper			
	*** **Unit Summary for Hunter 1 for the year 1995 =**		1,023.58	424,787.08
Hunter 2				
1.	01/24/95 00:29 - 01/25/95 01:09	Unplanned	24.67	10,236.67
	Descr: Boiler tube leak (steam cooled wall)			
2.	05/10/95 22:51 - 05/11/95 17:15	Unplanned	18.40	7,636.00
	Descr: Boiler tube leak (reheat section)			
3.	05/11/95 17:15 - 05/12/95 06:02	Unplanned	12.78	5,305.08
	Descr: Unit inefficiency (start-up mode)			
4.	09/21/95 00:04 - 09/23/95 16:00	Unplanned	63.93	26,532.33
	Descr: Off line - precip repair			

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Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Hunter 2						
5.	09/23/95 16:00	-	09/24/95 06:40	Unplanned	14.67	6,086.67
	Descr: Unit inefficiency (start-up mode)					
6.	09/24/95 11:07	-	09/24/95 17:23	Unplanned	6.27	2,600.67
	Descr: Unit off - coal feeder problems					
7.	11/07/95 16:08	-	11/08/95 04:30	Unplanned	12.37	5,132.17
	Descr: Unit trip (bfp problems)					
8.	12/21/95 00:00	-	12/22/95 04:45	Unplanned	28.75	11,931.25
	Descr: Boiler tube leak (reheat section)					
	*** **Unit Summary for Hunter 2 for the year 1995 =**				181.84	75,460.84
Hunter 3						
1.	01/27/95 23:10	-	01/28/95 05:35	Unplanned	6.42	2,534.58
	Descr: Off to clean stator y-strainer					
2.	01/28/95 05:35	-	01/28/95 07:58	Unplanned	2.38	941.42
	Descr: Turbine tripped on high vibration					
3.	01/28/95 08:52	-	01/28/95 10:50	Unplanned	1.97	776.83
	Descr: Turbine tripped on high vibration					
4.	01/28/95 10:50	-	01/28/95 13:31	Unplanned	2.68	1,059.92
	Descr: Turbine tripped on high vibration					
5.	03/02/95 23:00	-	03/03/95 14:00	Unplanned	15.00	5,925.00
	Descr: Lower waterwall annubar flange leak					
6.	03/03/95 14:00	-	03/03/95 18:45	Unplanned	4.75	1,876.25
	Descr: Reheater plugged with ash					
7.	03/03/95 18:45	-	03/03/95 21:00	Unplanned	2.25	888.75
	Descr: Flame scanner being replaced by i&c					
8.	03/03/95 21:00	-	03/04/95 00:00	Unplanned	3.00	1,185.00
	Descr: Lighter problems					
9.	03/04/95 00:00	-	03/04/95 02:00	Unplanned	2.00	790.00
	Descr: Fire in boiler - fighting drum swell					
10.	03/04/95 02:00	-	03/04/95 03:20	Unplanned	1.33	526.67
	Descr: Lighter problems					
11.	03/04/95 03:20	-	03/04/95 05:00	Unplanned	1.67	658.33
	Descr: Building pressure & doing chest warm					
12.	03/04/95 05:00	-	03/04/95 07:55	Unplanned	2.92	1,152.08
	Descr: South crh pot full of water					
13.	03/24/95 05:44	-	03/24/95 09:25	Unplanned	3.68	1,454.92
	Descr: Unit trip - black furnace trip					
14.	03/24/95 09:25	-	03/24/95 11:37	Unplanned	2.20	869.00
	Descr: I&c calibrating 762 power supply					
15.	03/24/95 11:37	-	03/24/95 15:53	Unplanned	4.27	1,685.33
	Descr: Bfpt vacuum trips will not reset					
16.	03/24/95 19:20	-	03/24/95 21:20	Unplanned	2.00	790.00
	Descr: Unit trip - black furnace trip					
17.	03/25/95 04:00	-	03/25/95 06:00	Unplanned	2.00	790.00
	Descr: I&c checking modules in 762 system					
18.	03/25/95 06:00	-	03/25/95 08:07	Unplanned	2.12	836.08
	Descr: Lighter problems					
19.	03/25/95 08:07	-	03/25/95 10:22	Unplanned	2.25	888.75
	Descr: Main common dr mov shaft broken					
20.	03/25/95 10:22	-	03/25/95 14:48	Unplanned	4.43	1,751.17
	Descr: Unit inefficiency (temps, press, etc.)					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Hunter 3						
21.	03/25/95 19:11	-	03/26/95 00:00	Unplanned	4.82	1,902.58
	Descr: I&c finishing work on power supply					
22.	07/23/95 02:50	-	07/23/95 11:40	Unplanned	8.83	3,489.17
	Descr: Unit off line - turbine trip					
23.	07/23/95 11:40	-	07/23/95 16:15	Unplanned	4.58	1,810.42
	Descr: Turbine eva problems					
24.	07/23/95 16:15	-	07/23/95 17:55	Unplanned	1.67	658.33
	Descr: 3-1 fd fan problems					
25.	07/23/95 17:55	-	07/24/95 00:00	Unplanned	6.08	2,402.92
	Descr: Problems with oil guns					
26.	07/24/95 00:00	-	07/24/95 07:43	Unplanned	7.72	3,048.08
	Descr: Problems with turbine eva logic					
27.	10/29/95 11:20	-	10/30/95 06:20	Unplanned	19.00	7,505.00
	Descr: Off line - problem with turbine eh system					
28.	10/30/95 07:20	-	10/30/95 08:20	Unplanned	1.00	395.00
	Descr: Unit tripped on low drum level					
	*** * * Unit Summary for Hunter 3 for the year 1995 =**				123.02	48,591.58
Huntington 1						
1.	02/06/95 00:00	-	02/07/95 18:05	Unplanned	42.08	17,675.00
	Descr: Tube leak					
2.	02/25/95 02:20	-	02/26/95 17:18	Unplanned	38.97	16,366.00
	Descr: Leak					
3.	02/26/95 17:18	-	02/27/95 09:18	Unplanned	16.00	6,720.00
	Descr: Tube leak					
4.	03/09/95 00:00	-	03/10/95 06:44	Unplanned	30.73	12,908.00
	Descr: (rear. sloping, #199) leak					
5.	03/23/95 03:48	-	03/23/95 18:05	Unplanned	14.28	5,999.00
	Descr: (rear steam cooled) leak					
6.	03/23/95 18:57	-	03/27/95 04:54	Unplanned	81.95	34,419.00
	Descr: Won't close completely					
7.	03/27/95 06:47	-	03/27/95 10:01	Unplanned	3.23	1,358.00
	Descr: Trip - main stop valves steam leak					
8.	05/02/95 02:24	-	05/05/95 10:37	Unplanned	80.22	33,691.00
	Descr: Deslagging					
9.	05/15/95 23:28	-	05/17/95 01:56	Unplanned	26.47	11,116.00
	Descr: Tube leak					
10.	05/19/95 20:28	-	05/22/95 06:00	Unplanned	57.53	24,164.00
	Descr: Inspection/repair					
11.	08/11/95 12:02	-	08/12/95 21:07	Unplanned	33.08	13,895.00
	Descr: Leak					
12.	08/14/95 18:30	-	08/14/95 21:38	Unplanned	3.13	1,316.00
	Descr: Not working					
13.	10/12/95 00:20	-	10/13/95 01:30	Unplanned	25.17	10,570.00
	Descr: Replacing					
14.	11/19/95 12:50	-	11/22/95 18:50	Unplanned	78.00	32,760.00
	Descr: Pluggage					
15.	12/01/95 02:30	-	12/02/95 15:40	Unplanned	37.17	15,610.00
	Descr: Tube leak					
16.	12/12/95 22:30	-	12/14/95 06:56	Unplanned	32.43	13,622.00
	Descr: Leak					

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Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Huntington 1						
17.	12/15/95 23:40	-	12/16/95 01:06	Unplanned	1.43	602.00
	Descr: Fell apart					
	* * * **Unit Summary for Huntington 1 for the year 1995 =**				601.87	252,791.00
Huntington 2						
1.	02/03/95 00:00	-	02/06/95 09:25	Unplanned	81.42	34,602.08
	Descr: Ash removal					
2.	02/14/95 21:17	-	02/15/95 11:22	Unplanned	14.08	5,985.42
	Descr: Steam leak					
3.	02/15/95 15:36	-	02/16/95 02:56	Unplanned	11.33	4,816.67
	Descr: Steam leak					
4.	02/16/95 12:18	-	02/16/95 14:07	Unplanned	1.82	772.08
	Descr: Lost pump					
5.	02/24/95 15:47	-	02/26/95 04:37	Unplanned	36.83	15,654.17
	Descr: Leak					
6.	02/26/95 04:52	-	02/26/95 05:58	Unplanned	1.10	467.50
	Descr: Low drum level					
7.	03/16/95 12:19	-	03/19/95 07:30	Unplanned	67.18	28,552.92
	Descr: (outlet terminal tube on finishing superheat assembly 37) leak					
8.	05/23/95 00:13	-	05/26/95 11:30	Unplanned	83.28	35,395.42
	Descr: Ash pluggage					
9.	06/16/95 12:00	-	06/16/95 15:45	Unplanned	3.75	1,593.75
	Descr:					
10.	06/21/95 23:45	-	06/23/95 21:54	Unplanned	46.15	19,613.75
	Descr: Leak					
11.	09/28/95 23:27	-	09/30/95 16:30	Unplanned	41.05	17,446.25
	Descr: Wash					
12.	09/30/95 16:30	-	10/02/95 09:30	Unplanned	41.00	17,425.00
	Descr: Realignment					
13.	11/16/95 23:45	-	11/20/95 01:38	Unplanned	73.88	31,400.42
	Descr: Wash					
	* * * **Unit Summary for Huntington 2 for the year 1995 =**				502.87	213,725.43
Jim Bridger 1						
1.	01/14/95 00:45	-	01/14/95 21:05	Unplanned	20.33	10,573.33
	Descr: Waterwall tube leak which then washed out a reheater tube.					
2.	02/14/95 05:27	-	02/14/95 10:20	Unplanned	4.88	2,539.33
	Descr: Unit off - condenser tube leak.					
3.	03/06/95 20:11	-	03/07/95 17:39	Unplanned	21.47	11,162.67
	Descr: Tube leak waterwall.					
4.	03/07/95 17:39	-	03/08/95 01:40	Unplanned	8.02	4,168.67
	Descr: Fuel oil pumps - leak in pumphouse.					
5.	03/08/95 01:40	-	03/08/95 04:17	Unplanned	2.62	1,360.67
	Descr: Fires in - start-up.					
6.	04/13/95 13:25	-	04/14/95 06:22	Unplanned	16.95	8,814.00
	Descr: Unit off line to deslag finishing superheater.					
7.	04/25/95 00:19	-	04/26/95 08:19	Unplanned	32.00	16,640.00
	Descr: Feedwater header leak.					
8.	05/05/95 07:25	-	05/06/95 07:40	Unplanned	24.25	12,610.00
	Descr: Repair waterwall tube leak.					
9.	06/05/95 13:46	-	06/06/95 23:58	Unplanned	34.20	17,784.00
	Descr: Unit off line to repair economizer inlet valve.					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger 1						
10.	06/26/95 14:46	-	06/26/95 18:01	Unplanned	3.25	1,690.00
	Descr: Boiler ph due to condenser tube leak.					
11.	06/28/95 21:31	-	06/29/95 14:39	Unplanned	17.13	8,909.33
	Descr: Unit off line to repair #11 i.d.fan vanes.					
12.	06/29/95 18:05	-	06/29/95 19:27	Unplanned	1.37	710.67
	Descr: Unit off line-low boiler ph-condenser tube leak,					
13.	06/30/95 12:02	-	07/01/95 07:15	Unplanned	19.22	9,992.67
	Descr: Unit off line to repair waterwall tube leak.					
14.	07/18/95 10:03	-	07/18/95 11:12	Unplanned	1.15	598.00
	Descr: Unit tripped - trip anticipator.					
15.	08/22/95 14:04	-	08/23/95 13:40	Unplanned	23.60	12,272.00
	Descr: Unit off to repair waterwall tube leaks.					
16.	08/23/95 13:40	-	08/23/95 19:54	Unplanned	6.23	3,241.33
	Descr: #12 aph won't rotate.					
17.	08/23/95 19:54	-	08/24/95 00:10	Unplanned	4.27	2,218.67
	Descr: Firing for start-up -- after waterwall tube leak.					
18.	08/30/95 00:39	-	08/30/95 20:02	Unplanned	19.38	10,079.33
	Descr: Tube leak -- waterwall.					
19.	09/17/95 16:59	-	09/17/95 23:26	Unplanned	6.45	3,354.00
	Descr: Suspected tube leak -- operator error.					
20.	09/25/95 18:25	-	09/27/95 21:23	Unplanned	50.97	26,502.67
	Descr: Unit off to deslag fsh.					
21.	10/22/95 00:29	-	10/24/95 04:47	Unplanned	52.30	27,196.00
	Descr: Unit off line to repair pendant platen wcs					
22.	10/24/95 07:55	-	10/26/95 00:44	Unplanned	40.82	21,224.67
	Descr: Unit off line to repair sh division panel tube leak.					
23.	11/01/95 01:44	-	11/02/95 03:17	Unplanned	25.55	13,286.00
	Descr: Sh tube leak.					
24.	12/07/95 08:09	-	12/09/95 11:27	Unplanned	51.30	26,676.00
	Descr: Unit off to repair rh tube leak in penthouse.					
25.	12/19/95 23:00	-	12/20/95 22:13	Unplanned	23.22	12,072.67
	Descr: Unit off to repair rh, sh, and ww tube leaks.					
	*** **Unit Summary for Jim Bridger 1 for the year 1995 =**				510.93	265,676.68
Jim Bridger 2						
1.	01/06/95 02:16	-	01/07/95 08:04	Unplanned	29.80	15,496.00
	Descr: Reheater tube leak.					
2.	01/08/95 13:23	-	01/09/95 02:23	Unplanned	13.00	6,760.00
	Descr: Unit off line to repair superheater tube leak.					
3.	02/23/95 23:52	-	02/25/95 03:48	Unplanned	27.93	14,525.33
	Descr: Boiler tube leak - rh pendants.					
4.	05/06/95 00:00	-	06/07/95 18:18	Planned	786.30	408,876.00
	Descr: Unit off line for planned outage.					
5.	06/29/95 13:07	-	07/01/95 04:37	Unplanned	39.50	20,540.00
	Descr: Unit off line to repair pendant platen tube leak.					
6.	07/01/95 07:57	-	07/01/95 14:38	Unplanned	6.68	3,475.33
	Descr: Relays burned up.					
7.	07/01/95 21:28	-	07/02/95 01:09	Unplanned	3.68	1,915.33
	Descr: Unit trip -- bad relay.					
8.	07/02/95 03:08	-	07/02/95 05:31	Unplanned	2.38	1,239.33
	Descr: Bad relay.					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger 2						
9.	07/02/95 09:40	-	07/02/95 11:26	Unplanned	1.77	918.67
	Descr: Unit trip -- bad relay.					
10.	07/15/95 06:04	-	07/15/95 07:27	Unplanned	1.38	719.33
	Descr: Condenser tube leak.					
11.	07/15/95 08:15	-	07/15/95 09:56	Unplanned	1.68	875.33
	Descr: Condenser tube leak -- ph less than 7.0					
12.	07/27/95 00:45	-	07/29/95 10:04	Unplanned	57.32	29,804.67
	Descr: Unit off to repair radiant rh tube leak.					
13.	07/30/95 13:20	-	07/30/95 14:20	Unplanned	1.00	520.00
	Descr: Unit tripped. blew thyristor bridge.					
14.	07/30/95 19:24	-	08/08/95 15:02	Unplanned	211.63	110,049.33
	Descr: Unit tripped - blew thyristor bridges.					
15.	08/24/95 02:11	-	08/25/95 04:24	Unplanned	26.22	13,632.67
	Descr: Boiler tube leak -- sh pendant platen.					
16.	08/27/95 15:59	-	08/29/95 08:13	Unplanned	40.23	20,921.33
	Descr: S.h. platen leak.					
17.	08/31/95 22:43	-	09/01/95 18:00	Unplanned	19.28	10,027.33
	Descr: Unit off -- tube leak finishing super heat.					
18.	10/09/95 23:59	-	10/11/95 03:50	Unplanned	27.85	14,482.00
	Descr: Unit off for tube leak repair.					
19.	10/16/95 16:51	-	10/18/95 06:41	Unplanned	37.83	19,673.33
	Descr: Unit off to repair generator hydrogen leak.					
20.	11/11/95 23:00	-	11/12/95 22:27	Unplanned	23.45	12,194.00
	Descr: Unit off to repair sh division panel bifurcate.					
	*** * * Unit Summary for Jim Bridger 2 for the year 1995 =**				1,358.91	706,645.31
Jim Bridger 3						
1.	01/15/95 13:52	-	01/15/95 17:37	Unplanned	3.75	1,950.00
	Descr: Ignitor problems.					
2.	01/15/95 17:37	-	01/15/95 19:36	Unplanned	1.98	1,031.33
	Descr: Unit start up after condenser tube leak.					
3.	02/14/95 13:45	-	02/17/95 05:00	Unplanned	63.25	32,890.00
	Descr: Exciter problems.					
4.	02/17/95 05:00	-	02/17/95 13:29	Unplanned	8.48	4,411.33
	Descr: Start-up problems - ignitors not working.					
5.	02/27/95 08:49	-	02/28/95 06:00	Unplanned	21.18	11,015.33
	Descr: Unit off to repair rh tube leak.					
6.	02/28/95 06:00	-	02/28/95 10:57	Unplanned	4.95	2,574.00
	Descr: Ignitor problems.					
7.	03/11/95 22:55	-	03/12/95 20:48	Unplanned	21.88	11,379.33
	Descr: Unit off to repair waterwall tube leak.					
8.	03/15/95 18:29	-	03/15/95 19:53	Unplanned	1.40	728.00
	Descr: Unit trip - lost kinport.					
9.	04/05/95 16:35	-	04/05/95 18:27	Unplanned	1.87	970.67
	Descr: Unit off line-low boiler ph.					
10.	06/04/95 23:55	-	06/08/95 23:00	Unplanned	95.08	49,443.33
	Descr: Unit off line to repair turbine valves and bearings.					
11.	06/15/95 20:30	-	06/16/95 00:07	Unplanned	3.62	1,880.67
	Descr: Condenser tube leak.					
12.	06/16/95 00:59	-	06/16/95 12:17	Unplanned	11.30	5,876.00
	Descr: Low boiler ph due to condenser tube leak.					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger 3						
13.	06/19/95 23:46	-	06/21/95 03:34	Unplanned	27.80	14,456.00
	Descr: Unit off line to repair waterwall tube leak.					
14.	09/06/95 12:59	-	09/06/95 16:40	Unplanned	3.68	1,915.33
	Descr: Unit tripped when bfbp's tripped.					
15.	09/27/95 06:13	-	09/27/95 08:55	Unplanned	2.70	1,404.00
	Descr: Unit trip - bcp delta p -- lost 31 bfbp.					
16.	10/06/95 06:15	-	10/06/95 08:00	Unplanned	1.75	910.00
	Descr: Tripped unit due to condenser tube leak -- boiler water ph @ 5.9.					
17.	10/06/95 08:00	-	10/06/95 17:00	Unplanned	9.00	4,680.00
	Descr: Unit to stay off to repair boiler tube leaks.					
18.	10/06/95 17:00	-	10/08/95 02:40	Unplanned	33.67	17,506.67
	Descr: Unit off to repalce #32 bcp.					
19.	10/08/95 09:22	-	10/08/95 15:31	Unplanned	6.15	3,198.00
	Descr: Condenser tube leak -- outside pass inlet.					
20.	10/08/95 16:07	-	10/08/95 22:35	Unplanned	6.47	3,362.67
	Descr: Condenser tube leak -- unit off.					
21.	10/09/95 02:00	-	10/09/95 03:02	Unplanned	1.03	537.33
	Descr: Unit off -- condenser tube leak.					
22.	10/29/95 08:57	-	10/29/95 10:25	Unplanned	1.47	762.67
	Descr: Unit tripped-32 bfp would not reset.					
23.	11/09/95 00:03	-	11/10/95 06:29	Unplanned	30.43	15,825.33
	Descr: Unit off for sh tube leak.					
24.	12/01/95 00:58	-	12/02/95 00:08	Unplanned	23.17	12,046.67
	Descr: Unit off line to repair 32 i.d. fan inlet vanes.					
25.	12/14/95 21:30	-	12/16/95 19:23	Unplanned	45.88	23,859.33
	Descr: Ac regulator problems-can't null.					
26.	12/20/95 15:51	-	12/20/95 19:16	Unplanned	3.42	1,776.67
	Descr: Unit off line to repair gen. liquid cooling system.					
	*** Unit Summary for Jim Bridger 3 for the year 1995 =				435.36	226,390.66
Jim Bridger 4						
1.	01/30/95 23:29	-	02/01/95 05:33	Unplanned	30.07	15,634.67
	Descr: Unit off line to repair sh tube leak.					
2.	02/14/95 03:22	-	02/15/95 08:45	Unplanned	29.38	15,279.33
	Descr: Off line to repair rh tube leak.					
3.	02/15/95 08:45	-	02/15/95 16:44	Unplanned	7.98	4,151.33
	Descr: Can't get aph to start.					
4.	03/31/95 21:32	-	04/29/95 00:03	Planned	673.52	350,228.67
	Descr: Planned overhaul.					
5.	05/09/95 02:49	-	05/09/95 04:30	Unplanned	1.68	875.33
	Descr: Unit trip-power load unbalance.					
6.	05/18/95 00:18	-	05/19/95 17:41	Unplanned	41.38	21,519.33
	Descr: Unit off line to repair reheater tube leak.					
7.	05/21/95 10:44	-	05/21/95 12:44	Unplanned	2.00	1,040.00
	Descr: Ehc pump failure.					
8.	05/31/95 13:31	-	06/03/95 16:21	Unplanned	74.83	38,913.33
	Descr: Unit off line to repack economizer inlet valve.					
9.	07/11/95 13:50	-	07/11/95 15:27	Unplanned	1.62	840.67
	Descr: Off line - boiler feed pump controls					
10.	07/19/95 00:00	-	07/19/95 20:29	Unplanned	20.48	10,651.33
	Descr: Unit off tube leak waterwall.					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Jim Bridger 4						
11.	09/08/95 00:13	-	09/09/95 06:10	Unplanned	29.95	15,574.00
	Descr: Unit off line to deslag boil reheater - hydrogen leak.					
12.	10/11/95 06:05	-	10/12/95 04:06	Unplanned	22.02	11,448.67
	Descr: Unit off to deslag pendant reheater.					
	*** **Unit Summary for Jim Bridger 4 for the year 1995 =**				934.91	486,156.66
Naughton 1						
1.	02/03/95 21:09	-	02/05/95 10:15	Unplanned	37.10	5,936.00
	Descr: Waterwall tube leak repairs, forney gas ignitors & flame scanner repa					
2.	03/18/95 17:56	-	03/20/95 22:06	Unplanned	52.17	8,346.67
	Descr: Offline to repair waterwall tube leak					
3.	04/09/95 10:22	-	04/09/95 16:55	Unplanned	6.55	1,048.00
	Descr: Condenser tube leak repairs					
4.	05/02/95 13:29	-	05/03/95 02:48	Unplanned	13.32	2,130.67
	Descr: Condenser tube leak repairs					
5.	05/26/95 10:56	-	05/26/95 15:21	Unplanned	4.42	706.67
	Descr: Unit tripped ups system short					
6.	06/07/95 08:44	-	06/07/95 11:25	Unplanned	2.68	429.33
	Descr: Excitation trip					
7.	07/22/95 00:20	-	07/22/95 09:09	Unplanned	8.82	1,410.67
	Descr: Condenser tube leaks					
8.	07/31/95 11:32	-	07/31/95 14:09	Unplanned	2.62	418.67
	Descr: Unit trip - problems with ups & forney burner mgt system					
9.	09/12/95 21:44	-	09/13/95 09:39	Unplanned	11.92	1,906.67
	Descr: Condenser tube leak repairs					
10.	09/24/95 12:33	-	09/27/95 05:17	Unplanned	64.73	10,357.33
	Descr: Waterwall roof tube ruptured					
11.	10/05/95 10:04	-	10/05/95 16:33	Unplanned	6.48	1,037.33
	Descr: Condenser tube leak					
12.	10/10/95 22:22	-	10/11/95 05:31	Unplanned	7.15	1,144.00
	Descr: Condenser tube leak					
13.	11/13/95 12:54	-	11/13/95 16:27	Unplanned	3.55	568.00
	Descr: Unit trip - relay made an error					
	*** **Unit Summary for Naughton 1 for the year 1995 =**				221.51	35,440.01
Naughton 2						
1.	01/04/95 12:33	-	01/04/95 14:44	Unplanned	2.18	458.50
	Descr: Relay dept. tripped unit					
2.	01/23/95 05:17	-	01/24/95 21:28	Unplanned	40.18	8,438.50
	Descr: Condenser tube leak repairs					
3.	01/25/95 21:58	-	01/26/95 07:05	Unplanned	9.12	1,914.50
	Descr: Condenser tube leak					
4.	02/07/95 10:57	-	02/08/95 09:24	Unplanned	22.45	4,714.50
	Descr: Unit off superheat tube leak repairs					
5.	02/08/95 09:24	-	02/08/95 10:38	Unplanned	1.23	259.00
	Descr: Startup failure following sh tube leak outage (per dispatch)					
6.	03/12/95 13:48	-	03/12/95 17:51	Unplanned	4.05	850.50
	Descr: Trip excitation system - voltage reg test					
7.	03/23/95 08:10	-	03/28/95 00:02	Unplanned	111.87	23,492.00
	Descr: Repair waterall tube leak -roof tube					
8.	04/27/95 00:54	-	04/30/95 02:30	Unplanned	73.60	15,456.00
	Descr: Forney repairing flame scanners					

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Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Naughton 2						
9.	04/30/95 02:30	-	04/30/95 04:24	Unplanned	1.90	399.00
	Descr: Field breaker would not close					
10.	05/14/95 14:44	-	05/14/95 20:47	Unplanned	6.05	1,270.50
	Descr: Offline, air preheater electrive drive, would not restart air drive					
11.	05/26/95 10:49	-	05/26/95 12:00	Unplanned	1.18	248.50
	Descr: Unit trip ups short					
12.	07/31/95 11:32	-	07/31/95 13:01	Unplanned	1.48	311.50
	Descr: Unit trip - problems with ups & forney burner mgt system (purge & trip					
13.	08/18/95 00:10	-	08/19/95 15:15	Unplanned	39.08	8,207.50
	Descr: Repair economizer tube leak					
14.	09/27/95 00:33	-	09/27/95 02:01	Unplanned	1.47	308.00
	Descr: Unit trip - flamer scanners					
15.	11/29/95 09:03	-	11/29/95 17:47	Unplanned	8.73	1,834.00
	Descr: Boiler ph low					
16.	11/29/95 17:47	-	11/30/95 16:24	Unplanned	22.62	4,749.50
	Descr: Boiler ph low - startup failure					
	*** * * Unit Summary for Naughton 2 for the year 1995 =**				347.19	72,912.00
Naughton 3						
1.	01/05/95 23:55	-	01/08/95 06:03	Unplanned	54.13	17,864.00
	Descr: Unit off-reheat tube leak; cleaning scrubber					
2.	01/08/95 11:26	-	01/11/95 02:54	Unplanned	63.47	20,944.00
	Descr: Unit off superheat tube leak					
3.	01/12/95 06:28	-	01/15/95 05:36	Unplanned	71.13	23,474.00
	Descr: Reheat header came apart; melted north drum room equipment					
4.	01/28/95 00:27	-	01/29/95 05:37	Unplanned	29.17	9,625.00
	Descr: Unit off-front reheater tube leak					
5.	02/14/95 00:56	-	02/14/95 02:04	Unplanned	1.13	374.00
	Descr: Boiler trip - low drum level					
6.	02/14/95 03:26	-	02/14/95 08:05	Unplanned	4.65	1,534.50
	Descr: Boiler trip - low drum level					
7.	02/16/95 23:51	-	02/17/95 10:27	Unplanned	10.60	3,498.00
	Descr: Condensate line going to da transmitter leak					
8.	03/11/95 00:31	-	03/13/95 05:42	Unplanned	53.18	17,550.50
	Descr: Planned outage- rod pluggage in reheater, turb intercept valve repair.					
9.	04/05/95 10:04	-	04/09/95 04:28	Unplanned	90.40	29,832.00
	Descr: Unit off to repair 2 superheat & 3 waterwall tube leaks					
10.	04/17/95 10:46	-	04/17/95 13:04	Unplanned	2.30	759.00
	Descr: Maintenance checking controls, trip 3-1 bfpt					
11.	05/01/95 22:05	-	05/02/95 21:26	Unplanned	23.35	7,705.50
	Descr: Unit off-blew 3-2 mcc					
12.	05/12/95 23:22	-	07/11/95 20:53	Planned	1,437.52	474,380.50
	Descr: Major boiler overhaul - replace reheater, cooling tower repairs, scrbr					
13.	07/18/95 23:58	-	07/19/95 01:32	Unplanned	1.57	517.00
	Descr: 3-2 bfpt lube oil dirty, trip causing drum level to trip boiler					
14.	07/19/95 04:23	-	07/19/95 12:50	Unplanned	8.45	2,788.50
	Descr: 3-1 bfpt tripped, 3-2 bfpt out					
15.	07/28/95 22:50	-	07/30/95 23:54	Unplanned	49.07	16,192.00
	Descr: Planned maint outage to replace cooling tower valves & fix ww tube lea					
16.	08/16/95 13:43	-	08/16/95 15:25	Unplanned	1.70	561.00
	Descr: Boiler tripped, lost 3-2 bfpt					

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No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Naughton 3						
17.	08/16/95 15:32	-	08/16/95 17:05	Unplanned	1.55	511.50
	Descr: Boiler tripped, lost 3-2 bfpt					
18.	08/23/95 23:18	-	08/25/95 06:49	Unplanned	31.52	10,400.50
	Descr: Waterwall tube leak					
19.	08/28/95 12:45	-	08/28/95 17:51	Unplanned	5.10	1,683.00
	Descr: Bfpt trip - cause unknown					
20.	09/08/95 19:08	-	09/08/95 20:15	Unplanned	1.12	368.50
	Descr: Unable to get slag off, putting pump back in, drum level trip					
21.	09/23/95 03:18	-	09/25/95 05:37	Unplanned	50.32	16,604.50
	Descr: Repair waterwall tube leaks (coutant slope) balance turbine					
22.	09/28/95 10:04	-	09/28/95 11:04	Unplanned	1.00	330.00
	Descr: Bfpt trip, belly drain tanks high level					
23.	10/19/95 10:09	-	10/21/95 02:28	Unplanned	40.32	13,304.50
	Descr: Tube leak in waterwalls by b-12, accomplished scrubber clean					
24.	10/22/95 05:53	-	10/22/95 15:02	Unplanned	9.15	3,019.50
	Descr: Repair 3b guillotine, chain broke, took links out					
25.	10/31/95 23:55	-	11/01/95 16:50	Unplanned	16.92	5,582.50
	Descr: Condenser tube leak repairs					
26.	11/04/95 08:49	-	11/04/95 23:18	Unplanned	14.48	4,779.50
	Descr: Condenser tube leak					
27.	11/05/95 11:19	-	11/05/95 22:52	Unplanned	11.55	3,811.50
	Descr: Low boiler ph					
28.	12/02/95 21:00	-	12/04/95 17:12	Unplanned	44.20	14,586.00
	Descr: Repair waterwall tube leaks, scrubber clean etc.					
29.	12/05/95 21:17	-	12/06/95 02:02	Unplanned	4.75	1,567.50
	Descr: Balance shot on hp turbine					
30.	12/15/95 06:40	-	12/15/95 08:01	Unplanned	1.35	445.50
	Descr: Low drum level trip caused by 3-2 bfpt					
31.	12/17/95 00:45	-	12/17/95 02:39	Unplanned	1.90	627.00
	Descr: Shift supervisor tripped unit					
	*** **Unit Summary for Naughton 3 for the year 1995 =**				2,137.05	705,221.00
Wyodak						
1.	01/08/95 00:07	-	01/08/95 21:07	Unplanned	21.00	7,035.00
	Descr: Waterwall tube leak					
2.	01/08/95 21:07	-	01/08/95 23:07	Unplanned	2.00	670.00
	Descr: Start-up delayed due to lighter problems.					
3.	01/08/95 23:07	-	01/09/95 06:07	Unplanned	7.00	2,345.00
	Descr: Ruptured turbine atmosphere relief due to high back pressure.					
4.	02/07/95 04:01	-	02/07/95 06:35	Unplanned	2.57	859.83
	Descr: Bailey net 90 computer shut down all acc fans. suspect an electrical					
5.	02/07/95 06:35	-	02/07/95 07:35	Unplanned	1.00	335.00
	Descr: Start-up delayed one hour due to lighter problems.					
6.	02/07/95 08:27	-	02/07/95 14:31	Unplanned	6.07	2,032.33
	Descr: Da inspection door gasket blown.					
7.	02/07/95 14:31	-	02/07/95 15:31	Unplanned	1.00	335.00
	Descr: Lighters plugged.					
8.	02/12/95 16:34	-	02/13/95 14:40	Unplanned	22.10	7,403.50
	Descr: Waterwall tube leak.					
9.	02/15/95 19:46	-	02/17/95 09:42	Unplanned	37.93	12,707.67
	Descr: Waterwall tube leak.					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Wyodak						
10.	02/17/95 09:42	-	02/17/95 11:12	Unplanned	1.50	502.50
	Descr: Start-up delayed due to lighter problems.					
11.	03/10/95 02:54	-	03/22/95 00:00	Planned	285.10	95,508.50
	Descr: Repair generator hydrogen leak					
12.	03/22/95 00:00	-	03/22/95 14:25	Planned	14.42	4,829.58
	Descr: Extended generator outage					
13.	03/22/95 14:25	-	03/22/95 16:25	Unplanned	2.00	670.00
	Descr: Start-up delayed due to lighter problems					
14.	04/22/95 14:16	-	04/22/95 18:28	Unplanned	4.20	1,407.00
	Descr: Reduced load to remove from line to repair a lightning arrestor on the					
15.	06/02/95 01:40	-	06/02/95 03:46	Unplanned	2.10	703.50
	Descr: Turbine tripped on high back pressure because an empty di tank was					
16.	07/15/95 19:46	-	07/31/95 07:40	Unplanned	371.90	124,586.50
	Descr: Suspect lightning struck main transformer, caused main transformer					
17.	08/03/95 05:16	-	08/05/95 01:30	Unplanned	44.23	14,818.17
	Descr: Reduced load to bring unit off for tube leak, unit tripped on mft at					
18.	10/07/95 00:07	-	10/07/95 18:13	Unplanned	18.10	6,063.50
	Descr: Fix boiler tube leak.					
19.	10/07/95 18:13	-	10/07/95 20:43	Unplanned	2.50	837.50
	Descr: Lighter problems during start-up.					
	*** Unit Summary for Wyodak for the year 1995 =				846.72	283,650.08
Cholla 4						
1.	01/12/95 23:17	-	01/15/95 21:45	Unplanned	70.47	26,777.33
	Descr: Precipitator repairs					
2.	01/17/95 07:34	-	01/17/95 08:53	Unplanned	1.32	500.33
	Descr: High drum level					
3.	01/17/95 09:29	-	01/17/95 13:27	Unplanned	3.97	1,507.33
	Descr: High drum level					
4.	02/28/95 13:15	-	02/28/95 18:33	Unplanned	5.30	2,014.00
	Descr: Warmup guns controls problem					
5.	04/10/95 03:00	-	04/10/95 12:20	Unplanned	9.33	3,546.67
	Descr: Exciter field breaker failure					
6.	04/23/95 17:02	-	04/23/95 19:25	Unplanned	2.38	905.67
	Descr: Regulator valve closed					
7.	05/23/95 01:40	-	05/23/95 14:00	Unplanned	12.33	4,686.67
	Descr: Generator excitation relay failure					
8.	06/27/95 21:36	-	06/28/95 14:06	Unplanned	16.50	6,270.00
	Descr: Clean waterbox and circ water inlet					
9.	07/08/95 00:52	-	07/08/95 02:27	Unplanned	1.58	601.67
	Descr: Bypass valve vibrated open, low ehc pressure					
10.	07/19/95 13:32	-	07/19/95 15:32	Unplanned	2.00	760.00
	Descr: B boiler feed pump motor went to ground					
11.	08/17/95 18:23	-	08/17/95 19:42	Unplanned	1.32	500.33
	Descr: "b" boiler feed pump oil leak					
12.	09/16/95 22:49	-	09/17/95 03:18	Unplanned	4.48	1,703.67
	Descr: Operator error during weekly valve test					
13.	09/17/95 04:41	-	09/17/95 05:50	Unplanned	1.15	437.00
	Descr: High drum level					
14.	09/30/95 18:16	-	10/02/95 05:36	Unplanned	35.33	13,426.67
	Descr: Cleaning the water box					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs Duration	MWH Lost
Cholla 4						
15.	11/27/95 07:26	-	11/27/95 10:43	Unplanned	3.28	1,247.67
	Descr: High drum level trip					
16.	11/27/95 11:04	-	11/27/95 12:12	Unplanned	1.13	430.67
	Descr: Main flame detector problem					
17.	12/11/95 06:00	-	12/11/95 11:16	Unplanned	5.27	2,001.33
	Descr: Feedwater flow upset					
18.	12/11/95 15:12	-	12/11/95 16:51	Unplanned	1.65	627.00
	Descr: Feedwater flow upset					
	*** Unit Summary for Cholla 4 for the year 1995 =				178.79	67,944.01
Gadsby 2						
1.	03/06/95 16:26	-	03/06/95 18:28	Unplanned	2.03	152.50
	Descr: Switching turbine lube oil coolers got a transient signal of low press					
2.	07/31/95 12:18	-	07/31/95 15:51	Unplanned	3.55	266.25
	Descr: #1 phase amp time trip relay failed. a new one was installed.					
3.	08/01/95 18:04	-	08/01/95 19:36	Unplanned	1.53	115.00
	Descr: 2-1 burner relay failed causing the boiler to trip.					
4.	08/03/95 17:11	-	08/04/95 22:03	Unplanned	28.87	2,165.00
	Descr: A secondary superheat tube leak was detected six tubes from the south					
5.	10/09/95 07:00	-	10/10/95 14:30	Unplanned	31.50	2,362.50
	Descr: While being down for economic reserve, a leak in the steam balance dru					
	*** Unit Summary for Gadsby 2 for the year 1995 =				67.48	5,061.25
Gadsby 3						
1.	03/03/95 22:50	-	03/04/95 08:44	Unplanned	9.90	990.00
	Descr: One condenser tube leak found in lower half of condenser on the north					
2.	03/04/95 21:25	-	03/06/95 05:25	Unplanned	32.00	3,200.00
	Descr: Found three condenser tube leaks after several hours of searching. ra					
3.	03/06/95 10:10	-	03/17/95 07:23	Unplanned	261.22	26,121.67
	Descr: Sodium levels reached 350 ppb and boiler ph dropped to 7. the ph was					
4.	03/24/95 23:36	-	03/26/95 06:35	Unplanned	30.98	3,098.33
	Descr: Tube leak in primary superheat section. leak was caused by disimilar					
5.	05/16/95 22:08	-	05/18/95 04:36	Unplanned	30.47	3,046.67
	Descr: Repaired boiler tube leak 9 rows from north 2 sections from west. wat					
6.	10/23/95 06:59	-	10/23/95 08:04	Unplanned	1.08	108.33
	Descr: Low vacuum trip during startup					
7.	11/05/95 10:40	-	11/06/95 04:04	Unplanned	17.40	1,740.00
	Descr: An outside disturbance in the system dropped the unit 3 generator to 3					
8.	11/06/95 04:04	-	11/06/95 05:06	Unplanned	1.03	103.33
	Descr: Start up failure					
	*** Unit Summary for Gadsby 3 for the year 1995 =				384.08	38,408.33
Blundell						
1.	01/15/95 11:00	-	01/15/95 14:30	Unplanned	3.50	80.50
	Descr: Unit tripped; b104 which feeds mcc b12 tripped					
2.	02/28/95 13:47	-	02/28/95 16:55	Unplanned	3.13	72.07
	Descr: B-104 tripped; direct ground caused tripping of mcc feed breaker					
3.	02/28/95 16:55	-	02/28/95 21:52	Unplanned	4.95	113.85
	Descr: Main steam line vent stack; i.g. control valve failed					
4.	03/01/95 07:42	-	03/01/95 18:53	Unplanned	11.18	257.22
	Descr: Off line-ig work on vent stack valve; will not close all the way					
5.	04/03/95 15:06	-	04/25/95 08:00	Planned	520.90	11,980.70
	Descr: Scheduled plant overhaul					

1995 PacifiCorp Thermal Unit Outages

Listed by Unit in Chronological Order - 1 Hr. Minimum Duration

No.	Beginning Date Time	-	Ending Date Time	Outage Type	Hrs. Duration	MWH Lost
Blundell						
6.	04/25/95 08:00	-	07/15/95 01:00	Unplanned	1,937.00	44,551.00
	Descr: Unit outage; extension of overhaul forced due to needed unplannedrepai					
7.	07/25/95 10:06	-	07/25/95 20:22	Unplanned	10.27	236.13
	Descr: Unit off line - make repairs on new h2s gas vent stack					
8.	09/06/95 03:04	-	09/06/95 19:50	Unplanned	16.77	385.63
	Descr: Inspect and repair front turbine steam seals					
9.	09/06/95 19:50	-	09/07/95 01:31	Unplanned	5.68	130.72
	Descr: Steam supplier vent valve failed					
10.	10/19/95 11:41	-	10/19/95 15:00	Unplanned	3.32	76.28
	Descr: Took unit off line to clean hotwell screens					
	*** **Unit Summary for Blundell for the year 1995 =**				2,516.70	57,884.10
Little Mtn.						
1.	08/21/95 07:00	-	09/01/95 15:30	Planned	272.50	3,815.00
	Descr: Replaced the fill in the cooling tower					
	*** **Unit Summary for Little Mtn. for the year 1995 =**				272.50	3,815.00

HYDRO FORCED OUTAGE REPORT
Outages of 24 hours or longer duration

Plant	Date	Time Offline	Date	Time On Line	Outage Hours	Reason
Toketee (Unit 1)	19-Jan-95	12:18	20-Jan-95	12:00	24	Turbine bearing over temperature
Toketee (Unit 3)	11-Jan-95	07:15	12-Jan-95	02:24	30	High temperature bearing trip
Toketee (Unit 3)	11-Nov-95	06:55	13-Nov-95	15:05	56	Turbine bearing temperature relay
Toketee (Unit 3)	25-Nov-95	17:30	28-Nov-95	14:45	69	Turbine bearing wiped
Condit 1	21-Aug-95	09:40	22-Aug-95	15:40	30	Bearing maintenance
Condit 1	30-Oct-95	15:21	02-Nov-95	09:30	66	Hot bearing
Cline Falls	15-Feb-95	04:30	16-Feb-95	10:30	30	Repack Packing Gland - leaking water
Big Fork	13-Jan-95	19:00	08-Feb-95	12:32	617	Canal washout (water restored thru woodstave)
Big Fork	21-Feb-95	09:36	01-Mar-95	12:19	222	Leak in canal wall
Big Fork	18-Nov-95	14:17	24-Nov-95	14:47	145	Thrust bearing oil seal leak
Big Fork	15-Dec-95	14:11	20-Dec-95	15:21	121	Leak in new canal joint
Powerdale	09-Aug-95	14:29	14-Aug-95	15:22	121	Repair voltage regulator
John C Boyle #1	01-Jan-95	00:00	09-Jan-95	09:12	225	Runner replacement; off for testing until release
John C Boyle #1	19-Jan-95	09:10	20-Jan-95	09:30	24	B.O. resister in BF circuit
John C Boyle #1	27-Feb-95	09:30	28-Feb-95	13:30	28	B.O. resister in BF circuit
John C Boyle #1	29-Aug-95	09:10	31-Aug-95	17:16	56	Intake Gate B.O.
John C Boyle #1	11-Sep-95	12:35	21-Sep-95	10:27	241	Cone replacement
John C Boyle #1	04-Oct-95	15:30	06-Oct-95	15:30	55	Cone replacement
John C Boyle #1	10-Oct-95	09:00	11-Oct-95	14:00	29	#1 speeder adj. B. O.
John C Boyle #2	21-Aug-95	11:06	23-Aug-95	14:11	51	RTD B.O. to thrustbearing
John C Boyle #2	29-Aug-95	09:10	31-Aug-95	17:16	56	Intake gate B.O.
Eastside	31-Jan-05	12:00	01-Feb-95	18:15	30	Mtr relay cutting in ESR plant unavailable
Eastside	11-May-95	09:00	23-May-95	16:20	319	Removed old lining, E.S. penstock
Eastside	11-Dec-95	09:20	17-Dec-95	10:00	148	E.S. penstock relining
Westside	23-May-95	09:51	30-May-95	14:50	173	Thrust bearing wipped
Copco 1	21-May-95	21:30	23-May-95	21:30	43	Bushing on BO transformer blew up
Copco 1	21-Nov-95	13:30	22-Nov-95	14:30	25	Replaced 2 broken wicket gate arms
Copco 2	25-Jun-95	08:00	30-Jun-95	11:30	124	Burned out exciter latch coil; governor oil pump out
Fall Creek (Unit 1)	11-Dec-95	10:00	01-Feb-95	08:40	1,255	Broken pivot pin and hydralic cylinder replacement
Fall Creek (Unit 2)	27-Jun-95	11:15	29-Jun-95	09:15	52	Repair made to nozzle gasket and nozzle ring
Fall Creek (Unit 2)	07-Jul-95	13:30	14-Jul-95	14:50	169	Leaking nozzle and erosion on nozzle ring repaired
American Fork	01-Jan-95		31-Dec-95		8,760	Plant shut down - ruptured flowline (down since 5/10/93)
Ashton	10-Jan-95		19-Jan-95		233	Ashton #2 - CT & closing coil failure / replaced
Oneida	12-Apr-95		17-Apr-95		153	Oneida #3 - Governor accumulator tank seal failed
Oneida	06-May-95		23-May-95		432	Oneida #1 - Governor oil system plugging up
Paris	01-Jan-95		03-Jan-95		42	Canal frozen - severe winter storm
Pioneer	20-Dec-95		31-Dec-95		288	Pioneer #6 - vibration problem - repaired headcover
Snakecreek	22-May-95		24-May-95		49	Snakecreek #2 - Burned up deflector coil / replaced
Soda	03-Jan-95		09-Jan-95		144	Soda #1 - Oil pump failure / replaced
Upper Beaver	01-Jan-95		12-Jan-95		264	Beaver #1 - 86 relay lockout burned up / replaced
Upper Beaver	16-May-95		17-May-95		38	Beaver #1 / #2 - Plugged needle valve/ hot bearing
Upper Beaver	05-Jun-95		10-Jun-95		120	Beaver #1 / #2 - Flowline break / repaired
Upper Beaver	26-Jun-95		27-Jun-95		29	Beaver #2 - Relay lockout burned up / replaced
Weber	06-May-95		25-May-95		475	Turbine bearing wiped / repaired - Penstock flange

HYDRO FORCED OUTAGE REPORT
Outages of 24 hours or longer duration

Plant	Date	Time Offline	Date	Time On Line	Outage Hours	Reason
Prospect 1	01-Jan-95		24-Mar-95		1,992	Repair of bad turbine seals
Prospect 1	14-Apr-95	09:32	19-May-95	12:40	843	Turbine and generator overheating / repaired
Prospect 2	29-Sep-95	09:00	04-Oct-95	16:24	127	Collector ring maintenance / exciter repair
Prospect 3	30-Dec-95	08:34	31-Dec-95	15:45	31	Clean trash racks due to heavy run off
Eagle Point	19-Jun-95	22:00	02-Jul-95	08:00	298	Repair of canal slide

Sch. 35 **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	Residential Weatherization									
2	Zero Interest Program									
3	Initiated - 1978	$3,924	$6,374	-38.44%						
4	Projected Life - to be rolled into SGC HIP in 1994									
5	Low Income Program									
6	Initiated - 1987	$40,448	$33,912	19.27%						
7	Projected Life - Indefinite									
8					0.03	288	0.01	68	(0.02)	(220)
9	Residential Appliance									
10	Efficient Heat Pumps									
11	Initiated - 1986	$2,540	$4,450	-42.92%						
12	Projected Life - Indefinite									
13	Efficient Water Heaters									
14	Initiated - 1987	$4,346	$3,977	9.28%						
15	Projected Life - Indefinite									
16	SERP									
17	Initiated - 1994	$7,561	$1,653	357.41%						
18	Projected Life - 1997									
19						41		40		(1)
20	New Residential									
21	Super Good Cents Home Improvement Pgm									
22	Initiated - 1993		$3	-100.00%						
23	Projected Life - Indefinite									
24	Super Good Cents									
25	Initiated - 1988	$182,901	$175,636	4.14%						
26	Projected Life - Indefinite									
27	Manufactured Aquisition Program (MAP)									
28	Initiated - 1991	$65,419	$181,037	-63.86%						
29	Projected Life - Indefinite									
30					0.04	351	0.05	470	0.01	119
31										
32										

Sch. 35 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	New Commercial									
2	Energy FinAnswer									
3	Initiated - 1991	$21,793	$10,011	117.69%						
4	Projected Life - Indefinite									
5	Energy FinAnswer 12,000									
6	Initiated - 1992		$12,811	-100.00%						
7	Projected Life - Indefinite									
8					0.02	175	0.02	203		28
9	Industrial									
10	Industrial FinAnwser									
11	Initiated - 1995	$3,297								
12	Projected Life - Indefinite									
13							0.16	1,359	0.16	1,359
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	TOTAL	$332,229	$429,864	-22.71%	0.09	855	0.24	2,140	0.15	1,285

Sch. 36

MONTANA CONSUMPTION AND REVENUES

	Sales of Electricity	Operating Revenues		MegaWatt Hours Sold		Avg. No. of Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$16,852,868	$16,247,784	334,967	320,176	27,825	27,065
2	Commercial - Small	11,580,152	11,265,384	249,616	243,793	5,172	5,003
3	Commercial - Large						
4	Industrial - Small	N.A.	1,230,779	N.A.	25,658	216	217
5	Industrial - Large	9,216,688	6,117,181	272,683	183,368	10	10
6	Interruptible Industrial						
7	Public Street & Highway Lighting	145,920	141,238	2,322	2,348	43	42
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities	8,597,128		303,999	276,415	1	
11	Interdepartmental						
12							
13	TOTAL	$46,392,756	$35,002,366	1,163,587	1,051,758	33,267	32,337

Excludes Other Electric Revenues.