YEAR 1999

ANNUAL REPORT

OF

The Montana Power Company

ELECTRIC UTILITY

The Montana Power Company

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 20261
HELENA, MT 59620-2601

CORRECTED COPY

Revised June 5, 2000

ELECTRIC ANNUAL REPORT

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Sch. 1

IDENTIFICATION

Legal Name of Respondent:	The Montana Power Company
Name Under Which Respondent Does Business:	The Montana Power Company
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	Ernest J. Kindt
Telephone Number for Report Inquiries:	(406) 497-2233
Address for Correspondence Concerning Report:	40 East Broadway Butte, Montana 59701

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.

NOT APPLICABLE

Sch. 2	**BOARD OF DIRECTORS**	
	Director's Name & Address (City, State)	Remuneration
1/	Alan F. Cain 515 S. Roberts St. Helena, MT 59601	$23,600
1/	R. D. Corette Corette, Pohlman & Kebe Law Firm P. O. Box 509 Butte, MT 59703	$23,100
1/	Kay Foster Planteriors Unlimited 1916 3rd Ave. N. Billings, MT 59102	$22,100
1/	Beverly D. Harris - Retired 12/31/99 PO Box 461 Livingston, MT 59047	$24,100
1/	Carl Lehrkind, III Lehrkind's, Inc. P. O. Box 10580 Bozeman, MT 59715	$22,600
1/	N. E. Vosburg Pacific Steel & Recycling P. O. Box 1549 Great Falls, MT 59403	$22,600
1/	John R. Jester Bargain Street, LLC 3610 S. Pine St Tacoma, WA 98409	$23,100
1/	Tucker Hart Adams US Bank 918 17th St, 6th Floor Denver, CO 80202	$23,600
1/	John G. Connors Microsoft Corporation 1 Microsoft Way, Building 11/2017 Redmond, WA 98052-6399	$22,100
1/	Deborah D. McWhinney Internet Profiles Corporation (I/PRO) 575 Market Street, 5th Floor San Francisco, CA 94105	$8,033

BOARD OF DIRECTORS

	Director's Name & Address (City, State)	Remuneration
2/	Robert P. Gannon The Montana Power Company 40 East Broadway Butte, MT 59701	$0
2/	Jerrold P. Pederson The Montana Power Company 40 East Broadway Butte, MT 59701	$0

1/ Remuneration:
Non-employee Directors are paid $19,600 per year, effective 12/1/96, plus $500 for each meeting of a Committee of the Board attended, except those held in conjunction with regular Board meetings.

They also receive $850 per special meeting of the Board, when such special meetings are held in addition to the regularly scheduled Board meeting in any one month.

The Company has a Deferred Compensation Plan for non-employee Directors.
Directors may elect to defer their payments as Directors until retirement from the Board.
No compensation was deferred in 1999.
Deferred payments earn interest based on Moody's average Baa Corporate Bond Rates.

The Company has a Stock Compensation Plan for non-employee Directors.
The Plan provides annual grants of 960 shares of the Company's common stock.
The Plan also allows Directors to elect to receive any portion of their annual retainer in the Company's common stock.
Directors may elect to defer receipt of the stock payment until they cease to be a Director of the Company or until such other date the Director elects.
At the end of the deferral period, the Director will be paid for the stock units in Company common stock or the equivalent value in cash based upon the market value of the Company's common stock at that time.

All Company Directors elected prior to 12/31/97participated in a non-qualified retirement plan (the Benefit Restoration Plan for Directors).
The Plan was implemented in 1986 for all eligible Directors.
This Plan provides for annual benefit payments to vested participants upon retirement.
It is intended to allow for supplemental income to the Director at the time of retirement or to beneficiaries in the event of the Director's death.
Trust owned life insurance is carried on Plan participants.
The Company and participants in the Plan contribute to the cost of the life insurance.
All death proceeds are specifically directed to the Plan Trust for the sole purpose of paying for Plan benefits and premium costs.
The board curtailed the Plan, effective 12/31/97, by closing it to additional participants and by capping the maximum annual benefits to eliminate further increases to benefits as the annual retainer increases.

2/ Employee Directors do not receive compensation for board and/or committee meetings.

Sch. 3

OFFICERS

Title	Department Supervised	Name
Chairman of the Board, President and Chief Executive Officer	Executive - Shared Administrative Services (Corporate Communications) (Governmental Affairs) (Corporate Community Relations)	Robert P. Gannon
Vice Chairman and Chief Financial Officer	Executive - Shared Administrative Services (Audit Services) (Controller Services) (Information Services) (Strategic Planning) (Treasury Services) (Financial Reporting) (EVA Planning)	Jerrold P. Pederson
Vice President, Human Resources and Secretary	Executive - Shared Administrative Services (Investor Services) (Flight Services) (Human Resources)	Pamela K. Merrell
Vice President and General Counsel	Executive - Shared Administrative Services (Legal) (Land & Enviromental Services)	Michael E. Zimmerman
Vice President	Marketing (Market Research and Analysis and Advertising)	W. Stephen Dee (retired effective March 31,2000)
Executive Vice President and Chief Operating Officer	Energy Services Division (Regulatory Affairs)	John D. Haffey
Vice President	Distribution Services	David A. Johnson
Vice President	Transmission Services	William A. Pascoe
Vice President	Corporate Business Development	Perry J. Cole
Vice President	Business Development/ Technology Division [Touch America, Inc.]	Perry J. Cole
Executive Vice President and Chief Operating Officer	Technology Division [Touch America, Inc.]	Michael J. Meldahl
Executive Vice President and Chief Operating Officer	Energy Supply Division	Richard F. Cromer
Chief Information Officer	Shared Administrative Services	Daniel J. Sullivan

Sch. 3 cont.

OFFICERS

Title	Department Supervised	Name
Treasurer	Treasury Services	Ellen M. Senechal
Treasurer	Technology Division [Touch America, Inc.] and Continental Energy Services, Inc.	Treasury Services
Controller	Controller Services	David S. Smith
Controller	Telecommunications Division	Carol Giamona
Assistant Controller	Controller Services	Ernest J. Kindt
Assistant Treasurer	Treasury Services	Treasury Services
Assistant Secretary	Executive - Shared Administrative Services	Susan D. Breining
Assistant Secretary	Investor Services	Rose Marie Ralph

Sch. 4	**CORPORATE STRUCTURE**			
	Subsidiary/Company Name	Line of Business	Earnings (000)	% of Total
1				
2	**THE MONTANA POWER COMPANY**			
3	**Utility Operations**		$61,364	41.84%
4	Electric Utility	Electric Utility		
5	Natural Gas Utility	Natural Gas Utility		
6	Canadian-Montana Pipe Line Corporation	Natural Gas Transmission		
7	Glacier Gas Company	Production & Transmission of Natural Gas		
8	Colstrip Community Services Company	Water and Refuse Services		
9	Montana Power Services Company	Service Provider for the Company		
10	Montana Power Capital 1	Financing		
11	MPC Natural Gas Funding Trust	Bond Transition Financing		
12				
13	**Nonutility Operations**		$85,292	58.16%
14	Colstrip Unit 4 Lease Mgmt Division	1/ Wholesale Sales of Electric Power		
15	Continental Energy Services, Inc.	Independent Power & Cogen. Dev. & Invest.		
16	EMPECO, Inc.	Independent Power & Cogen. Dev. & Invest.		
17	EMPECO II, Inc.	Independent Power & Cogen. Dev. & Invest.		
18	EMPECO V, Inc.	Independent Power & Cogen. Dev. & Invest.		
19	EMPECO VI-TE, Inc.	Independent Power & Cogen. Dev. & Invest.		
20	EMPECO VII-TX3, Inc.	Independent Power & Cogen. Dev. & Invest.		
21	Montana Energy , Inc.	Independent Power & Cogen. Dev. & Invest.		
22	ECI Energy, Ltd.	2/ Investment in British Partnership in a		
23		Natural Gas-Fired Cogeneration Project		
24	Enserch Development Corp. One, Inc.	Generate Electricity		
25	Montana Grimes County, Inc.	Ownership in Electric Power Generating Facility		
26	Montana Grimes Frontier, Inc.	Ownership in Electric Power Generating Facility		
27	CES International	Independent Power & Cogen. Dev. & Invest.		
28	Barge Energy LLC	Holding Co. for Power Plant Investment		
29	PAK Energy LLC	Holding Co. for Power Plant Investment		
30	Entech, Inc.	Admin. & Mgmt. of Nonutility Services, excluding		
31		Colstrip 4 Lease & Continental Energy Services		
32	Canadian-Montana Gas Company Ltd.	Natural Gas Exploration & Development		
33	Altana Exploration Company	Oil & Natural Gas Exploration & Development		
34	Montana Power Ventures, Inc.	Information & Natural Gas Transportation Services		
35	Entech Gas Ventures, Inc.	Information & Natural Gas Transportation Services		
36	Altana Exploration, Ltd.	Oil & Natural Gas Exploration & Development		
37	The Montana Power Gas Company	Natural Gas Supplier for Montana Markets		
38	North American Resources Company	Oil & Natural Gas Exploration & Development		
39	Western Energy Company	Coal & Minerals Mining		
	Western SynCoal Company			
40	SynCoal, Inc.	Develop Coal Drying Technology		
41	Montana Energy Development	Investment in Mining Resource Ventures		
42	Participacoes, Ltda.			
43	Finaciera Ulken Sociedad Anonima	Financing		
44	Northwestern Resources Company	Lignite & Minerals Mining		
45	Basin Resources, Inc.	Underground Coal Mining		
46	Horizon Coal Services, Inc.	Coal Sales & Development		
47	North Central Energy Company	Exploration, Develop. & Production of Coal		
48				
49	1/ Colstrip Unit 4 Lease Management Division is an operating division of The Montana Power Company.			
50				
51	2/ Continental Energy Services owns 47.5 % of the value and 50% of the voting power of this corporation.			

Sch. 4

CORPORATE STRUCTURE

	Subsidiary/Company Name	Line of Business	Earnings (000)	% of Total
1	SynCoal, Incorporated	Clean Coal Technology Development		
2	Tetragenics Company	Process Control Systems		
3	Touch America, Inc.	Telecommunications Systems & Equipment		
4	The Montana Power Trading and Marketing Company	Energy Brokerage and Marketing		
5				
6	**TOTAL**		$146,656	100.00%

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Shared Administrative Services - 1/					
Executive Management & Office of the Corporation Secretary	Includes the following departments: CEO & Chairman; Vice Chairman & CFO Vice Pres. & Secretary; Vice Pres. & CLC; Corporate Communications; Governmental and Legislative Affairs; Environmental Compliance Flight Services; Investor Services; Community Relations; MPC Foundation; Vice-Pres. - Marketing; Market Research and Planning Strategic Planning.	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	$10,277,994	62.27%	$6,227,881
Human Resources	Includes the following departments: Human Resources; Benefits; Compensation & Labor Relations; Employment; Organizational Development; Technology Training; HR Liaison to Energy Supply; HR Liaison to Energy Services	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	$19,900,786	73.81%	$7,061,800
Financial Accounting	Includes the following departments: Audit Services; Commodity Risk; Controller Administration; Corporate Accounting; Property Records; Corporate Tax; Disbursements; Financial Reporting; CS Liaison to Energy Supply; CS Liaison to Energy Services; G&T Admin. Services; Gas Oper. Admin. Services	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	$5,202,717	65.94%	$2,687,017
Treasury Services & Facilities	Includes the following departments: Treasury Services; Facilities; Mailing Services; Financial Services; Financial Systems; Investor Relations; Risk Mgmt.; Credit and Cash	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	$7,596,864	63.34%	$4,397,401

Sch. 5 cont.

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Information Services	Includes the following departments: Information Services; IS Customer Services; Admin. & User Support; Applications; Text Services; Information Tech Services; Data Administration; Data Center Operations; Network Services; Security & Disaster Recovery; IS Liaison to Energy Supply; IS Liaison to Energy Services; IS Liaison to SAS; Internet Communications	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on %'s developed using formulas based on net plant, revenues and gross payroll.	$12,925,178	85.53%	$2,187,088
Legal Services	Legal Services Department	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on %'s developed using formulas based on net plant, revenues and gross payroll.	$1,044,267	67.13%	$511,379
Common Items	Includes: accruals for injuries and damages; pension trust fund payments; deferred savings plan payments	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	$1,205,920	92.86%	$92,695
TOTAL			$58,153,726	71.51%	$23,165,261

1/ - Shared Administrative Services (SAS) became effective August 1, 1996. The purpose of SAS is to centralize overhead functions that are shared by all business units. Prior to August 1, 1996, only corporate costs were allocated. However, with the development of SAS, several departments that were separately maintained within MPC and Entech, Inc. have been combined and are now being allocated to the business segments.

Sch. 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Revs.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3	Western Energy Company	Coal sales & transportation	Contract Rates	$24,852,714	2.98%	$24,852,714
4		Misc. Services	Actual Costs Incurred	107,897	0.01%	107,897
5	North American Resources	By-product sales	Market Rates	43,372	0.01%	43,372
6	Tetragenics	Engineering Services	Market Rates	487,129	0.06%	487,129
7	Touch America, Inc.	Communication Services	Market Rates	883,977	0.11%	883,977
8	Entech, Inc.	Interest on notes	Interest rate used is average of MPC's	1,404,272	0.17%	1,404,272
9			short term borrowing rate & Colstrip			
10			Unit 4's portfolio investment rate.			
11			1999 Annual Average Rate=5.2000%			
12	North American Energy Services	Power plant O & M Services	Market Rates	3,345,383	0.40%	3,345,383
13	Continental Energy Services, Inc.	Interest on loans	Interest rate used is average of MPC's	6,062,707	0.73%	6,062,707
14			short term borrowing rate & Colstrip			
15			Unit 4's portfolio investment rate.			
16			1999 Annual Average Rate=5.2000%			
17	Colstrip Unit 4 -	Interest on loans	Interest rate used is average of MPC's	714,746	0.09%	714,746
18	Lease Management Division		short term borrowing rate & Colstrip			
19			Unit 4's portfolio investment rate.			
20			1999 Annual Average Rate=5.2000%			
21	**Total Nonutility Subsidiaries**			$37,902,197	4.54%	$37,902,197
22	**Total Nonutility Subsidiaries Revenues**			$835,300,000		
23	**Utility Subsidiaries**					
24	Glacier Gas Company	Gas sales	Based Upon Rate Base	$129,285	0.02%	$129,285
25	**Total Utility Subsidiaries**			$129,285	0.02%	$129,285
26	**Total Utility Subsidiaries Revenues**			$582,296,000		
27	**TOTAL AFFILIATE TRANSACTIONS**			$38,031,482		$38,031,482
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Sch. 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3	Western Energy Company	Sales of Electricity	Tariff Schedules	$1,819,670	0.25%	$1,819,670
4		Project Services	Actual Costs Incurred	252,656	0.03%	252,656
5	North American Resources	Gas Transportation	Monthly Bid Rate(FERC Tariff)	604	0.00%	604
6			& Fixed Rate (NEB)			
7	Touch America, Inc.	Sales of Gas & Electricity	Tariff Schedules	27,923	0.00%	27,923
8	Rosebud SynCoal	Sale of Coal	Actual Costs Incurred	78,597	0.01%	78,597
9	**Total Nonutility Subsidiaries**			$2,179,450	0.30%	$2,179,450
10	**Total Nonutility Subsidiaries Expenses**			$730,547,000		
11	**Utility Subsidiaries**					
12	Colstrip Community Services	Project Services	Actual Costs Incurred	$38,828	0.01%	$38,828
13	**Total Utility Subsidiaries**			$38,828	0.01%	$38,828
14	**Total Utility Subsidiaries Expenses**			$455,171,000		
15	**TOTAL AFFILIATE TRANSACTIONS**			$2,218,278		$2,218,278

Sch. 8	MONTANA UTILITY INCOME STATEMENT - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$488,770,208	$2,843,568	$485,926,640	$474,649,003	2.38%
3						
4	**Total Operating Revenues**	$488,770,208	$2,843,568	$485,926,640	$474,649,003	2.38%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expenses	$242,701,678	$1,620,847	$241,080,831	$219,020,019	10.07%
9	402 Maintenance Expense	30,970,932	199,148	30,771,784	29,333,729	4.90%
10	403 Depreciation Expense	51,233,821	377,917	50,855,904	49,389,936	2.97%
11	404-405 Amort. of Electric Plant	2,186,484		2,186,484	2,681,682	-18.47%
12	406 Amort. of Plant Acquisition Adj.	94,914		94,914	94,914	0.00%
13	407 Amort. of Property Losses,					
14	Unrecovered Plant, and					
15	Regulatory Study Costs					
16	408.1 Taxes Other Than Income Taxes	50,857,524		50,857,524	46,316,076	9.81%
17	409.1 Income Taxes - Federal	21,469,165	110,062	21,359,103	25,173,340	-15.15%
18	- Other	4,605,580	7,238	4,598,342	4,792,276	-4.05%
19	410.1 Deferred Income Taxes-Dr.	6,265,835	52,932	6,212,903	2,271,905	173.47%
20	411.1 Deferred Income Taxes-Cr.					
21	411.4 Investment Tax Credit Adj.	(2,038,886)	(3,629)	(2,035,257)	(1,243,075)	-63.73%
22	411.6 Gain from Disposition of Property					
23	411.7 Loss from Disposition of Property					
24						
25	**Total Operating Expenses**	$408,347,047	$2,364,515	$405,982,532	$377,830,802	7.45%
26	**NET OPERATING INCOME**	$80,423,161	$479,053	$79,944,108	$96,818,201	-17.43%
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Sch. 9	MONTANA REVENUES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Sales to Ultimate Consumers**					
3						
4	440 Residential	$130,005,204	$113,358	$129,891,846	$127,753,410	1.67%
5	442 Commercial	144,964,858	329,495	144,635,363	168,210,643	-14.02%
6	Industrial	72,835,312		72,835,312	80,525,263	-9.55%
7	444 Public Street & Highway Lighting	6,023,921	5,614	6,018,307	5,637,841	6.75%
8	445 Other Sales to Public Authorities	3,412,286	2,395,101	1,017,185	1,910,983	-46.77%
9	446 Sales to Railroads & Railways					
10	448 Interdepartmental Sales	613,054		613,054	746,062	-17.83%
11						
12	**Total Sales to Ultimate Consumers**	$357,854,634	$2,843,568	$355,011,066	$384,784,202	-7.74%
13	447 Sales for Resale	$108,916,562		$108,916,562	$72,644,108	49.93%
14						
15	**Total Sales of Electricity**	$466,771,196	$2,843,568	$463,927,628	$457,428,310	1.42%
16	449.1 Provision for Rate Refunds			$0	$0	-
17						
18	**Total Revenue Net of Rate Refunds**	$466,771,196	$2,843,568	$463,927,628	$457,428,310	1.42%
19						
20	**Other Operating Revenues**					
21						
22	451 Miscellaneous Service Revenue	$31,192		$31,192	$10,897	186.24%
23	453 Sales of Water & Water Power	2,708,554		2,708,554	2,953,820	-8.30%
24	454 Rent From Electric Property	2,276,168		2,276,168	2,423,846	-6.09%
25	455 Interdepartmental Rents					
26	456 Other Electric Revenues	16,983,098		16,983,098	11,832,130	43.53%
27						
28	**Total Other Operating Revenue**	$21,999,012	$0	$21,999,012	$17,220,693	27.75%
29	**TOTAL OPERATING REVENUE**	$488,770,208	$2,843,568	$485,926,640	$474,649,003	2.38%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1	**Power Production Expenses**					
2	**Steam Power Generation-Operation**					
3	500 Supervision & Engineering	$1,282,881		$1,282,881	$1,363,808	-5.93%
4	501 Fuel	32,644,628		32,644,628	30,210,113	8.06%
5	502 Steam Expenses	2,834,514		2,834,514	2,935,865	-3.45%
6	503 Steam from Other Sources	(2,828)		(2,828)	(2,283)	-23.87%
7	505 Electric Plant	2,124,704		2,124,704	2,254,243	-5.75%
8	506 Miscellaneous Steam Power	2,936,558		2,936,558	3,147,264	-6.69%
9	507 Rents	0		0	(33,680)	100.00%
10	**Total Operation-Steam Power Gen.**	$41,820,457	$0	$41,820,457	$39,875,329	4.88%
11	**Steam Power Generation-Maintenance**					
12	510 Supervision & Engineering	$520,358		$520,358	$507,767	2.48%
13	511 Structures	1,011,327		1,011,327	1,014,260	-0.29%
14	512 Steam Boiler Plant	8,179,735		8,179,735	6,941,240	17.84%
15	513 Electric Plant	2,048,200		2,048,200	1,414,180	44.83%
16	514 Miscellaneous Steam Plant	1,353,573		1,353,573	1,177,004	15.00%
17	**Total Maintenance-Steam Power Gen.**	$13,113,193	$0	$13,113,193	$11,054,452	18.62%
18	**Total Steam Power Generation**	$54,933,650	$0	$54,933,650	$50,929,781	7.86%
19	**Hydro Power Generation-Operation**					
20	535 Supervision & Engineering	$1,776,868		$1,776,868	$1,812,263	-1.95%
21	536 Water for Power	665,041		665,041	570,200	16.63%
22	537 Hydraulic Expenses	658,841		658,841	724,744	-9.09%
23	538 Electric Expenses	1,794,685		1,794,685	1,931,736	-7.09%
24	539 Miscellaneous Hydraulic Power	755,949		755,949	782,198	-3.36%
25	540 Rents	13,808,133		13,808,133	13,818,633	-0.08%
26	**Total Operation-Hydro Power Gen.**	$19,459,517	$0	$19,459,517	$19,639,773	-0.92%
27	**Hydro Power Generation-Maintenance**					
28	541 Supervision & Engineering	$179,727		$179,727	$239,170	-24.85%
29	542 Structures	136,883		136,883	251,741	-45.63%
30	543 Reservoirs, Dams & Waterways	860,723		860,723	1,070,977	-19.63%
31	544 Electric Plant	676,608		676,608	768,699	-11.98%
32	545 Miscellaneous Hydro Plant	297,982		297,982	295,091	0.98%
33	**Total Maintenance-Hydro Power Gen.**	$2,151,923	$0	$2,151,923	$2,625,678	-18.04%
34	**Total Hydraulic Power Generation**	$21,611,440	$0	$21,611,440	$22,265,452	-2.94%
35	**Other Power Generation-Operation**					
36	546 Supervision & Engineering					
37	547 Fuel	$62,221	$62,221	0	0	0.00%
38	548 Generation Expenses	3,719	$3,719	0	0	0.00%
39	549 Miscellaneous Other Power	6	$6	0	0	0.00%
40	**Total Operation-Other Power Gen.**	$65,946	$65,946	$0	$0	0.00%
41	**Other Power Generation-Maintenance**					
42	551 Supervision & Engineering					
43	552 Structures	$0	$0	$0	$0	0.00%
44	553 Generating & Electric Plant	34,187	34,187	0	0	0.00%
45	554 Miscellaneous Other Power Plant	8,467	8,467	0	0	0.00%
46	**Total Maintenance-Other Power Gen.**	$42,654	$42,654	$0	$0	0.00%
47	**Total Other Power Generation**	$108,600	$108,600	$0	$0	0.00%
48	**Other Power Supply Expenses**					
49	555 Purchased Power	$90,749,157	$1,076,630	$89,672,527	$82,535,819	8.65%
50	556 System Control & Load Dispatch	1,536		1,536	6,843	-77.55%
51	557 Other Expenses	0		0	0	-
52	**Total Other Power Supply Expenses**	$90,750,693	$1,076,630	$89,674,063	$82,542,662	8.64%
53	**Total Power Production Expenses**	$167,404,383	$1,185,230	$166,219,153	$155,737,894	6.73%

Sch. 10 cont.	MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)					
	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Expenses**					
3						
4	**Transmission-Operation**					
5	560 Supervision & Engineering	$2,637,501	$17,748	$2,619,753	$2,322,379	12.80%
6	561 Load Dispatching	1,235,078		1,235,078	1,298,097	-4.85%
7	562 Station Expenses	161,831		161,831	196,951	-17.83%
8	563 Overhead Lines	732,048	16,510	715,538	685,996	4.31%
9	564 Underground Lines					
10	565 Transmission of Elec. by Others	4,140,820		4,140,820	4,612,845	-10.23%
11	566 Miscellaneous Transmission	272,333		272,333	300,342	-9.33%
12	567 Rents	1,398,769		1,398,769	1,897,104	-26.27%
13	**Total Operation-Transmission**	$10,578,380	$34,258	$10,544,122	$11,313,712	-6.80%
14	**Transmission-Maintenance**					
15	568 Supervision & Engineering	$605,275	$345	$604,930	$415,944	45.44%
16	569 Structures	1,308	389	919	886	3.67%
17	570 Station Equipment	1,389,485	27	1,389,458	1,567,385	-11.35%
18	571 Overhead Lines	2,026,677	$102,453	1,924,224	1,826,288	5.36%
19	572 Underground Lines	(2,269)		(2,269)	259	-977.21%
20	573 Miscellaneous Transmission Plant	4,824		4,824	6,330	-23.80%
21	**Total Maintenance-Transmission**	$4,025,300	$103,214	$3,922,086	$3,817,093	2.75%
22	**Total Transmission Expenses**	$14,603,680	$137,472	$14,466,208	$15,130,805	-4.39%
23						
24	**Distribution Expenses**					
25						
26	**Distribution-Operation**					
27	580 Supervision & Engineering	$1,679,667	$933	$1,678,734	$1,131,657	48.34%
28	581 Load Dispatching	30		30	7	314.94%
29	582 Station Expenses	585,903	12,318	573,585	762,313	-24.76%
30	583 Overhead Lines	2,869,193	84,064	2,785,129	2,891,977	-3.69%
31	584 Underground Lines	1,005,456	25,307	980,149	1,118,953	-12.40%
32	585 Street Lighting & Signal Systems	838,546		838,546	852,873	-1.68%
33	586 Meters	2,067,885	942	2,066,943	2,392,061	-13.59%
34	587 Customer Installations	1,290,954	1,016	1,289,938	1,306,182	-1.24%
35	588 Miscellaneous Distribution	2,031,190		2,031,190	2,085,203	-2.59%
36	589 Rents	88,503		88,503	82,192	7.68%
37	**Total Operation-Distribution**	$12,457,327	$124,580	$12,332,747	$12,623,420	-2.30%
38	**Distribution-Maintenance**					
39	590 Supervision & Engineering	$654,801		$654,801	$711,751	-8.00%
40	591 Structures	20,908		20,908	86	24282.51%
41	592 Station Equipment	1,604,670	$2,671	1,601,999	1,433,098	11.79%
42	593 Overhead Lines	6,613,816	30,030	6,583,786	6,712,282	-1.91%
43	594 Underground Lines	1,327,308	18,723	1,308,585	1,485,806	-11.93%
44	595 Line Transformers	686,023	1,147	684,876	646,628	5.92%
45	596 Street Lighting, Signal Systems	452,789		452,789	528,010	-14.25%
46	597 Meters	455,353	708	454,645	511,820	-11.17%
47	598 Miscellaneous Distribution Plant	0		0	994	-100.00%
48	**Total Maintenance-Distribution**	$11,815,668	$53,279	$11,762,389	$12,030,476	-2.23%
49	**Total Distribution Expenses**	$24,272,995	$177,859	$24,095,136	$24,653,895	-2.27%
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51						
52						
53						

Sch. 10 cont.

MONTANA OPERATION & MAINTENANCE EXPENSES - ELECTRIC (EXCLUDES UNIT 4)

Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
Customer Accounts Expenses					
Customer Accounts-Operation					
901 Supervision	$0		$0	$0	-
902 Meter Reading	1,508,957		1,508,957	2,392,282	-36.92%
903 Customer Records & Collection	7,245,941		7,245,941	3,469,297	108.86%
904 Uncollectible Accounts	1,024,780		1,024,780	1,298,872	-21.10%
905 Miscellaneous Customer Accts.	230		230	211	9.25%
Total Customer Accounts Expenses	$9,779,908	$0	$9,779,908	$7,160,662	36.58%
Customer Service & Information					
Customer Service-Operation					
907 Supervision	$61,464		$61,464	$80,876	-24.00%
908 Customer Assistance	2,193,117		2,193,117	2,071,131	5.89%
909 Inform. & Instruct. Advertising	323,379		323,379	570,915	-43.36%
910 Misc. Customer Service & Info.	552		552	731	-24.49%
Total Customer Service & Info. Expense	$2,578,512	$0	$2,578,512	$2,723,653	-5.33%
Sales Expenses					
Sales-Operation					
911 Supervision	$207,356		$207,356	$232,769	-10.92%
912 Demonstrating & Selling	501,375		501,375	849,045	-40.95%
913 Advertising	92,887		92,887	379,087	-75.50%
916 Miscellaneous Sales	1,842		1,842	2,664	-30.84%
Total Sales Expenses	$803,460	$0	$803,460	$1,463,563	-45.10%
Administrative & General Expenses					
Admin. & General-Operation					
920 Admin. & General Salaries	$20,352,456	$139,548	$20,212,908	$20,673,792	-2.23%
921 Office Supplies & Expenses	5,441,993	37,313	5,404,680	4,999,825	8.10%
922 Admin. Expense Transferred-Cr.	(4,117,083)	(28,229)	(4,088,854)	(3,297,227)	-24.01%
923 Outside Services Employed	5,335,916	36,586	5,299,330	3,893,055	36.12%
924 Property Insurance	505,882	3,469	502,413	557,963	-9.96%
925 Injuries & Damages	3,130,173	21,462	3,108,711	3,755,842	-17.23%
926 Employee Pensions & Benefits	(3,059,418)	(16,736)	(3,042,682)	(5,926,048)	48.66%
927 Franchise Requirements					
928 Regulatory Commission Expenses	1,332,575		1,332,575	974,095	36.80%
407 Amortization of Property Losses	6,927,517		6,927,517	6,071,821	14.09%
929 Duplicate Charges-Cr.					
930 Miscellaneous General Expenses	10,538,659	72,259	10,466,400	4,412,078	137.22%
931 Rents	5,023,548	34,444	4,989,104	2,635,735	89.29%
Total Operation-Admin. & General	$51,412,218	$300,116	$51,112,102	$38,750,932	31.90%
Admin. & General-Maintenance					
935 General Plant	$2,817,455	$19,318	$2,798,137	$2,732,344	2.41%
Total Maintenance-Admin. & General	$2,817,455	$19,318	$2,798,137	$2,732,344	2.41%
Total Admin. & General Expenses	$54,229,673	$319,434	$53,910,239	$41,483,276	29.96%
TOTAL OPER. & MAINT. EXPENSES	$273,672,610	$1,819,995	$271,852,615	$248,353,748	9.46%

Sch. 11

MONTANA TAXES OTHER THAN INCOME - ELECTRIC (EXCLUDES UNIT 4)

Line	Description	Last Year	This Year	% Change
2	**Federal Taxes**			
3	Social Security Old Age	$2,788,630	$3,257,879	16.83%
4	Social Security Unemployment	97,708	257,809	163.86%
5	Excise Tax on Insurance Premiums			
6	Environmental Tax 1/	0	0	-
7	Medicare	784,715	835,311	6.45%
9	**Montana Taxes**			
10	Real Estate & Personal Property	43,785,532	46,290,117	5.72%
9	Montana Beneficial Use Tax	0	170,339	-
10	Crow Tribe Railroad & Utility Tax	0	45,621	-
11	Social Security Unemployment	121,139	(9,585)	-107.91%
11	Old Fund Liability	276,513	(1,624)	-100.59%
12	Units 3 & 4 Transmission Property	0	1,238,110	-
13	Electric Energy Producer's License	1,671,040	1,653,071	-1.08%
14	Consumer Counsel	294,975	347,761	17.90%
15	Public Service Commission	918,876	918,736	-0.02%
16	City Licenses	8,722	9,841	12.83%
18	**Wyoming Taxes**			
19	Property	0	0	-
21	**Washington Taxes**			
22	Social Security Unemployment	0	0	-
24	**District of Columbia Taxes**			
25	Social Security Unemployment	518	216	-58.30%
26	Personal Property	174	139	-19.85%
28	**Other**			
29	Payroll Tax Credit	(4,432,466)	(4,156,217)	6.23%
31	**TOTAL TAXES OTHER THAN INCOME**	$46,316,076	$50,857,524	9.81%

34 1/ Corporate environmental tax expired 12/31/95.

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES				
	Name of Recipient	Nature of Service	Total	MT	% MT
1	ARC ELECTRIC INC	MISC. ELECTRIC SERVICE	$142,345	1/	1/
2	ALME CONSTRUCTION, INC.	GAS PIPELINE CONSTRUCTION	115,421		
3	ALSTOM ESCA CORPORATION	MAINTENANCE	354,158		
4	AMERICAN PUBLIC LAND EXCHANGE	REAL ESTATE NEGOTIATION	263,674		
5	AMERICAN SOFTWARE USA	SOFTWARE MAINTENANCE	170,000		
6	ASPLUNDH	TREE TRIMMING	1,607,292		
7	ATS, ANDERSON TREE SERVICE	TREE TRIMMING	457,536		
8	BENCHMARKING PARTNERS, INC.	BENCHMARKING SERVICES	268,674		
9	BILL FIELD TRUCKING INC.	EQUIPMENT TRANSPORTATION	321,276		
10	BLUE CROSS/BLUE SHIELD OF MT	ADMINISTRATION - WELFARE PLAN	1,016,509		
11	BUCK CONSULTANTS, INC.	ADMINISTRATION - 401(K) PLAN	201,472		
12	BURNS INT'L. SECURITY SERVICES	SECURITY SERVICE	184,221		
13	COMANCHE DRILLING COMPANY	DRILLING	132,908		
14	COMMUNITY HEALTH OPTIONS	HEALTH SERVICES	369,253		
15	COMPUTER ASSOCIATES	MAINTENANCE	604,235		
16	DEAN CONKLIN	CONSULTING	111,014		
17	COVINGTON & BURLING	LEGAL	295,800		
18	CROWLEY,HAUGHEY,HANSON & TOOLE	LEGAL	587,748		
19	DAVIS WRIGHT TREMAINE	LEGAL	344,780		
20	DAVIS, GRAHAM & STUBBS L.L.C.	LEGAL	123,193		
21	DELOITTE & TOUCHE	ERP CONSULTING	340,355		
22	EPRI	RESEARCH	511,500		
23	EXPRESS SERVICES INC	TEMPORARY EMPLOYMENT	438,256		
24	FIRE SUPPRESSION SYSTEMS, INC.	FIRE SECURITY SERVICES	111,059		
25	FIRST DATA PAYMENT SERVICES	MISC. INFORMATION	234,969		
26	GEAC COMPUTER SYSTEMS INC	SATTELITE SERVICES	118,093		
27	GREGORY & COOK INC	PIPELINE CONSULTANT	2,732,322		
28	HARP LINE CONSTRUCTORS CO.	LINE CONSTRUCTION AND MAINTENANCE	4,393,320		
29	HEATH CONSULTANTS, INC.	GAS LEAK DETECTION	102,153		
30	HOWREY & SIMON	ENVIRONMENTAL CONSULTANT	125,332		
31	HUNTER BROTHERS CONSTRUCTION	EXCAVATION	101,328		
32	IBEX CONSTRUCTION	TREE TRIMMING	229,442		
33	IBM CORPORATION	COMPUTER MAINTENANCE	5,798,922		
34	INDEPENDENT INSPECTION COMPANY	ELECTRIC LINE INSPECTION	660,104		
35	INTERIM PERSONNEL BUTTE MT	TEMPORARY EMPLOYMENT	165,661		
36	ITRON INC	HARDWARE / SOFTWARE MAINTENANCE	573,981		
37	JAMES J MURPHY	CONSULTING	163,000		
38	JAMES TALCOTT CONSTRUCTION INC.	MISC. CONSTRUCTION	128,541		
39	JOHNSON CONTROLS, INC.	HVAC SYSTEM ADDITIONS	107,222		
40	LEWIS CONSTRUCTION COMPANY	MAINTENANCE / CONSTRUCTION	119,824		
41	MEYLAN ENTERPRISES, INC.	HIGH PRESSURE WASHING	231,759		
42	MIKE BOYLAN EXCAVATING, INC.	CONSTRUCTION / MAINTENANCE	127,437		
43	MILBANK TWEED HADLEY & MCCLOY	LEGAL	1,250,725		
44	MOODY'S INVESTOR SERVICES	INVESTOR SERVICES	108,934		
45	NATURAL GAS SERVICES	GAS SERVICE WORK	104,901		
46	NORTHERN TRUST COMPANY	CONSULTING 401(K) / PENSION	105,163		
47	NORTHWEST ENERGY EFFICIENCY	ENERGY SERVICES	513,667		
48	OLSEN & GRAFF	PRODUCTION SUPERVISION	229,658		
49	ORCOM SOLUTIONS	PROGRAMMING & IMPLEMENTATION	3,769,326		
50	PAR ELECTRICAL CONTRACTORS INC	LINE MAINTENANCE	108,362		
51	PRICEWATERHOUSECOOPERS LLP	AUDITING	802,334		
52	PROFESSIONAL ACCESS	CONSULTING	124,889		
53	ROBERT T MNOOKIN	MEDIATORS	159,693		
54	SAP AMERICA, INC.	MAINTENANCE	526,572		

Sch.12 cont.	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES				
	Name of Recipient	Nature of Service	Total	MT	% MT
1	SIEMANS WESTINGHOUSE POWER	TURBINE MODIFICATION	110,352		
2	SPIKER COMMUNICATIONS INC	ADVERTISING / TYPESETTING	774,283		
3	STERN STEWART & CO	VALUATION ANALYSIS	112,034		
4	STSTCS INC	LINE LOCATING	1,214,343		
5	TABBERT CONSTRUCTION	TRENCHING	232,091		
6	TAMIETTE CONSTRUCTION CO	MISC. CONSTRUCTION	105,747		
7	THELEN REID & PRIEST LLP	LEGAL	443,135		
8	TOWERS, PERRIN	CONSULTING / ACTUARY	311,560		
9	TRADE MARK ELECTRIC INC	ELECTRICAL WORK	232,443		
10	TRI-COUNTY MECHANICAL AND	MISC. PLUMBING	846,285		
11	UNITED INDUSTRY INC.	CONSTRUCTION & ADMINISTRATION	104,289		
12	WHITESIDE & ASSOCS	TRAFFIC CONSULTANTS	215,662		
13	WILLIAM M MERCER, INC.	BENEFIT CONSULTING	120,733		
14	WILLIAMS CONSTRUCTION	ELECTRIC LINE MAINTENANCE	5,392,099		
15	WOLFER PRINTING COMPANY	PRINTING SERVICES	151,847		
16	XEROX CORPORATION	MAINTENANCE	157,074		
17	ZACHA CONSTRUCTION, INC.	CONSTRUCTION / MAINTENANCE	171,175		
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53	**TOTAL PAYMENTS FOR SERVICE**		$43,685,465		
54	1/ Due to the multiple % allocations, it is not practical to separately identify amounts charged to the electric or gas utility.				

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS			
	Description	Total Company	Montana	% Montana

The Montana Power Company does not make any contributions to Political Action Committees (PACs) or candidates.

There is an employee PAC - Citizens for Responsible Government / Employees of The Montana Power Company (CRG). CRG is an organization of employees and shareholders of Montana Power and its subsidiaries. All of the money contributed by members goes to support political candidates. No company funds may be spent in support of a political candidate. Officers and local representatives of CRG donate their time. Nominal administrative costs for such things as duplicating and postage are paid by the Company. These costs are charged to shareholder expense.

Sch. 14

PENSION COSTS

	Description	Last Year	This Year	% Change
1	**Plan Name: Retirement Plan for Employees**			
2	**of The Montana Power Company**			
3	Defined Benefit Plan	Yes	Yes	
4	Defined Contribution Plan (See Schedule 14A)			
5	Is the Plan overfunded?	Yes - 2/	Yes - 3/	
6				
7				
8	Actuarial Cost Method	Projected Unit Credit Method		
9	IRS Code			
10	Annual Contribution by Employer	$0	$0	
11				
12	Accumulated Benefit Obligation	$220,164,382	$202,668,644	-7.95%
13	Projected Benefit Obligation	$181,421,763	$154,225,053	-14.99%
14	Fair Value of Plan Assets	$222,484,326	$204,921,941	-7.89%
15				
16	Discount Rate for Benefit Obligations	6.75%	7.75%	
17	Expected Long-Term Return on Assets	9.00%	9.00%	
18				
19	Net Periodic Pension Cost:			
20	Service Cost	$4,320,941	$5,038,661	16.61%
21	Interest Cost	11,975,208	13,023,645	8.76%
22	Return on Plan Assets (Expected)	(17,592,262)	(19,597,988)	-11.40%
23	Net Amortization	(513,324)	(112,893)	78.01%
24	Curtailment Charge	0	(3,750,922)	-
25	Settlement Charge	0	(7,844,276)	-
26	Total Net Periodic Pension Cost	($1,809,437)	($13,243,773)	-631.93%
27				
28	Minimum Required Contribution			
29	Actual Contribution	$0	$0	-
30	Maximum Amount Deductible /4	$0	$0	-
31	Benefit Payments	$8,799,269	$9,416,644	7.02%
32				
33	Montana Intrastate Costs:			
34	Pension Costs	NOT AVAILABLE		
35	Pension Costs Capitalized			
36	Accumulated Pension Asset (Liability) at Year End			
37				
38	Number of Company Employees : 1/			
39	Covered by the Plan			
40	Active	1,595	1,557	-2.38%
41	Retired	803	825	2.74%
42	Vested Former Employees (Deferred Inactive)	424	556	31.13%
43	Total Covered by the Plan	2,822	2,938	4.11%
44	Total Not Covered by the Plan			
45				

46 1/ Obtained from The Actuarial Valuation Report of the Retirement Plan for Employees of The
47 Montana Power Company, prepared as of January 1, 1998 and 1999 respectively.

49 2/ As of December 31, 1998, the fair value of assets was $222.5 million and the projected benefit obligation
50 was $181.4 million. However, there was an unrecognized net gain of $44.3 million that has not been
51 fully amortized pursuant to SFAS Statement No. 87. There is a prepaid pension cost of $4 million
52 as of December 31,1998.

54 3/ As of December 31, 1999, the fair value of assets was $204.9 million and the projected benefit obligation
55 was $154.2 million. However, there was an unrecognized net gain of $45.7 million that has not been
56 fully amortized pursuant to SFAS Statement No. 87. There is a prepaid pension cost of $5.9 million
57 as of December 31,1999.

59 4/ 1998 number was restated. An incorrect amount was reported in 1998.

Sch. 14A	PENSION COSTS			
	Description	Last Year - 3/	This Year	% Change
1	**Plan Name: Retirement Savings Plan**			
2				
3	Defined Benefit Plan (See Schedule 14)			
4	Defined Contribution Plan	Yes	Yes	
5	Is the Plan overfunded?			
6				
7				
8	Actuarial Cost Method			
9	IRS Code			
10	Annual Contribution by Employer			
11				
12	Accumulated Benefit Obligation			
13	Projected Benefit Obligation			
14	Fair Value of Plan Assets	$330,350,727	$217,103,334	-34.28%
15				
16	Discount Rate for Benefit Obligations			
17	Expected Long-Term Return on Assets			
18				
19	Net Periodic Pension Cost:			
20	Service Cost			
21	Interest Cost		NOT APPLICABLE	
22	Return on Plan Assets (Actual)			
23	Net Amortization			
24	Total Net Periodic Pension Cost			
25				
26	Minimum Required Contribution			
27	Actual Contribution		NOT APPLICABLE	
28	Maximum Amount Deductible			
29	Benefit Payments			
30				
31	Montana Intrastate Costs:			
32	Pension Costs		NOT APPLICABLE	
33	Pension Costs Capitalized			
34	Accumulated Pension Asset (Liability) at Year End			
35				
36	Number of Company Employees :			
37	Covered by the Plan -- Eligible	2,442	1,129	-53.77%
38	Not Covered by the Plan	0	0	0.00%
39	Active -- Participating	1,767	885	-49.92%
40	Retired			0.00%
41	Vested Former Employees, Retirees and	675	244	-63.85%
42	Active-Noncontributing			
43	Total Covered by the Plan	2,442	1,129	-53.77%
44	Total Not Covered by the Plan	0	0	
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Sch 15 **OTHER POST EMPLOYMENT BENEFITS (OPEBS)**

	Description	Last Year	This Year	% Change
1	**General Information**	1/	2/	
2	Discount Rate for Benefit Obligations	7.00%	6.75%	-3.57%
3	Expected Long-Term Return on Assets	9.00%	9.00%	0.00%
4	Medical Cost Inflation Rate 3/	8.00%, 5.00%: 6	7.50%,5.00%: 5	
5	Actuarial Cost Method	Projected Unit Credit Actuarial		
6		Cost Method allocated from date of		
7		hire to full eligibility date.		
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Total Company**			
15				
16	Accumulated Post Retirement Benefit Obligation (APBO)	$24,412,733	$16,706,651	-31.57%
17	Fair Value of Plan Assets	$8,781,999	$8,709,459	-0.83%
18				
19	List the amount funded through each funding method:			
20	VEBA	$860,014	$1,070,467	24.47%
21	401(h)	688,343	1,114,160	61.86%
22	Other: Cash	817,775	632,133	-22.70%
23	Total Amount Funded	$2,366,132	$2,816,760	19.04%
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA	$860,014	$1,070,467	24.47%
27	401(h)	688,343	1,114,160	61.86%
28	Other: Cash	817,775	632,133	-22.70%
29	Total Amount Tax Deductible	$2,366,132	$2,816,760	19.04%
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost	$775,597	$548,259	-29.31%
33	Interest Cost	1,658,296	1,429,031	-13.83%
34	Return on Plan Assets (Expected)	(670,497)	(645,008)	3.80%
35	Amort. Of Transition Oblig. & Regulatory Asset	1,095,162	954,713	-12.82%
36	Amortization of Prior Service Cost	68,832	134,876	95.95%
37	Amortization of Gains or Losses	(273,925)	(100,336)	63.37%
38	Total Net Periodic Post Retirement Benefit Cost	$2,653,465	$2,321,535	-12.51%
39	Benefit Cost Expensed	$1,614,899	$1,412,886	-12.51%
40	Benefit Cost Capitalized	446,047	390,250	-12.51%
41	Benefit Cost Charged to MPC Subs & Colstrip Owners	592,519	518,399	-12.51%
42	Total Benefit Costs	$2,653,465	$2,321,535	-12.51%
43	Benefit Payments	$817,775	$632,133	-22.70%
44				
45	Number of Company Employees :			
46	Covered by the Plans			
47	Active	1,579	1,551	-1.77%
48	Retired	645	650	0.78%
49	Retired Spouse/Dependents	72	68	-5.56%
50	Total Covered by the Plans	2,296	2,269	-1.18%
51	Total Not Covered by the Plans	230	251	9.13%
52	1/ Obtained from MPC's 1998 FASB 106 Valuation. Assumptions and data are as of December 31,1998.			
53	2/ Obtained from MPC's 1999 FASB 106 Valuation. Assumptions and data are as of December 31, 1999.			
54	3/ First Year, Ultimate, Years to Reach Ultimate.			

Sch 15A	OTHER POST EMPLOYMENT BENEFITS (OPEBS)			
	Description	Last Year	This Year	% Change
1	**General Information**	4/	4/	
2	Discount Rate for Benefit Obligations			
3	Expected Long-Term Return on Assets			
4	Medical Cost Inflation Rate 3/			
5	Actuarial Cost Method			
6				
7				
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Montana**	4/	4/	
15				
16	Accumulated Post Retirement Benefit Obligation (APBO)			
17	Fair Value of Plan Assets			
18				
19	List the amount funded through each funding method:			
20	VEBA			
21	401(h)			
22	Other: Cash			
23	Total Amount Funded			
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA			
27	401(h)			
28	Other: Cash			
29	Total Amount Tax Deductible			
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost			
33	Interest Cost			
34	Return on Plan Assets - Estimated			
35	Amort. of Transition Oblig. & Regulatory Asset			
36	Amortization of Gains or Losses			
37	Total Net Periodic Post Retirement Benefit Cost			
38	Benefit Cost Expensed			
39	Benefit Cost Capitalized			
40	Benefit Cost Charged to MPC Subs & Colstrip Owners			
41	Total Benefit Costs			
42	Benefit Payments			
43				
44	Number of Company Employees :			
45	Covered by the Plans			
46	Active			
47	Retired			
48	Retired Spouse/Dependents			
49	Total Covered by the Plans			
50	Total Not Covered by the Plans			
51	4/ Substantially all of the amounts are subject to the PSC jurisdiction. Actual amounts that will be			
52	expensed, will reflect reductions for amounts billed to others or allocated to Yellowstone National Park.			
53				

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

	Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
1	R. P. Gannon	$399,946	$8,654 <A			
2	Chairman of the Board		5,763 <B			
3	President and Chief Executive		263,671 <C			
4	Officer		126,000 <D			
5			83,426 <E			
6			2,264 <G			
7			338 <H			
8			481 <I			
9			550 <J	$891,093	$1,084,537	-18%
10	R.F. Cromer	$164,800	$33,488 <A			
11	Executive Vice President &		6,400 <B			
12	Chief Operating Officer, Energy		117,187 <C			
13	Supply Division		84,000 <D			
14			671 <G			
15			573 <H			
16			330 <I			
17						
18				$407,449	$310,019	31%
19	J. D. Haffey	$176,190	$19,000 <A			
20	Executive Vice President &		6,400 <B			
21	Chief Operating Officer, Energy		115,356 <C			
22	Services Division		84,000 <D			
23			539 <G			
24			60 <H			
25			530 <I			
26			2,769 <J			
27				$404,844	$431,139	-6%
28	J. P. Pederson	$200,022	$6,400 <B			
29	Vice Chairman & Chief Financial		112,915 <C			
30	Officer		60,000 <D			
31			485,438 <E			
32			1,139 <G			
33			374 <I			
34				$866,288	$285,007	204%
35	W. S. Dee	$176,485	$6,400 <B			
36	Vice President, Marketing		65,918 <C			
37			182 <G			
38			319 <H			
39			426 <I	$249,730	$216,616	15%
35	P. Gatzemeier					
36	Former - Vice President of	CONFIDENTIAL INFORMATION				
37	Coal Operations					
38		NOT REQUIRED FOR GENERAL DISTRIBUTION				
40	B. Graving					
41	Executive Director Strategic					
42	Planning					
43						
44	M. E. Zimmerman					
45	Vice President & General					
46	Counsel					
47						
48						
49						
50						
51						

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

Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
M. Meldahl Executive Vice President & Chief Operating Officer - Technology Division [Touch America, Inc.]	CONFIDENTIAL INFORMATION NOT REQUIRED FOR GENERAL DISTRIBUTION				
D. Johnson Vice President, Distribution Services					

1/ Salary includes the employees' annual base federally taxable earnings, pretax contributions to the Company's Deferred Savings and Employee Stock Ownership (401(K)) Plan, pretax Section 125 flexible spending account contributions, pretax medical premium contributions, and, in some cases, tax deferred Executive Benefit Restoration Plan contributions.

2/ All Other Compensation for named employees consists of the following:

A> Vacation time sold back to the Company. The vacation sellback program is available to all employees.

B> The value of the Company's matching contribution of stock made to the employee's accounts under the Deferred Savings and Employee Stock Ownership (401(K)) Plan sponsored by the Company.

C> Incentive Compensation Plan which were earned under the 1997 and 1998 EVA Bonus Plan.

D> Dividend equivalents on stock options awarded under the Long-Term Incentive Plan in 1994. These awards, approved by the Personnel Committee, were based on certain performance criteria.

E> Gains on exercised stock options.

F> Payout of stock under the Restricted Stock Plan. The Plan was based on certain 1994 performance criteria.

G> Imputed taxable income on Company-paid life insurance premiums.

H> Company-paid physical examinations.

I> Employee discounts on electric and gas utilities. Discounts were available to all Utility employees.

J> Personal use of company vehicles.

K> Spot cash bonus awards.

L> Severance pay.

Sch. 17 **COMPENSATION OF TOP FIVE CORPORATE EMPLOYEES - SEC INFORMATION**

Line	Name/Title	Base Salary 1/	Other Comp. 2/		Total Comp.	Total Comp. Last Year	% Change
1	R. P. Gannon	$399,946	$8,654	<A			
2	Chairman of the Board		5,763	<B			
3	President and Chief Executive		263,671	<C			
4	Officer		126,000	<D			
5			83,426	<E			
6			2,264	<G			
7			338	<H			
8			481	<I			
9			550	<J	$891,093	$1,084,537	-18%
10	R.F. Cromer	$164,800	$33,488	<A			
11	Executive Vice President &		6,400	<B			
12	Chief Operating Officer, Energy		117,187	<C			
13	Supply Division		84,000	<D			
14			671	<G			
15			573	<H			
16			330	<I			
17							
18					$407,449	$310,019	31%
19	J. D. Haffey	$176,190	$19,000	<A			
20	Executive Vice President &		6,400	<B			
21	Chief Operating Officer, Energy		115,356	<C			
22	Services Division		84,000	<D			
23			539	<G			
24			60	<H			
25			530	<I			
26			2,769	<J			
27					$404,844	$431,139	-6%
28	J. P. Pederson	$200,022	$6,400	<B			
29	Vice Chairman & Chief Financial		112,915	<C			
30	Officer		60,000	<D			
31			485,438	<E			
32			1,139	<G			
33			374	<I			
34					$866,288	$285,007	204%
35	W. S. Dee	$176,485	$6,400	<B			
36	Vice President, Marketing		65,918	<C			
37			182	<G			
38			319	<H			
39			426	<I	$249,730	$216,616	15%

40
41 1/ Salary includes the employees' annual base federally taxable earnings, pretax contributions to the
42 Company's Deferred Savings and Employee Stock Ownership (401(K)) Plan, pretax Section 125
43 flexible spending account contributions, pretax medical premium contributions, and, in some cases, tax
44 deferred Executive Benefit Restoration Plan contributions.
45 2/ All Other Compensation for named employees consists of the following:
46 A> Vacation time sold back to the Company. The vacation sellback program is available to all employees.
47 B> The value of the Company's matching contribution of stock made to the employee's accounts under
48 the Deferred Savings and Employee Stock Ownership (401(K)) Plan sponsored by the Company.
49 C> Incentive Compensation Plan which were earned under the 1997 and 1998 EVA Bonus Plan.
50 D> Dividend equivalents on stock options awarded under the Long-Term Incentive Plan in 1994. These awards,
51 approved by the Personnel Committee, were based on certain performance criteria.
52 E> Gains on exercised stock options.
53 F> Payout of stock under the Restricted Stock Plan. The Plan was based on certain 1994 performance criteria.
54 G> Imputed taxable income on Company-paid life insurance premiums.
55 H> Company-paid physical examinations.
56 I> Employee discounts on electric and gas utilities. Discounts were available to all Utility employees.
57 J> Personal use of company vehicles.
58 K> Spot cash bonus awards.
59 L> Severance pay.

Sch. 18	BALANCE SHEET 1/, 2/			
	Account Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	**Utility Plant**			
3	101 Plant in Service	$2,143,205,818	$1,151,900,735	-46.25%
4	105 Plant Held for Future Use	1,774,042	8,983	-99.49%
5	107 Construction Work in Progress	37,966,278	3,781,637	-90.04%
6	108 Accumulated Depreciation Reserve	(711,771,021)	(446,763,168)	37.23%
7	111 Accumulated Amortization & Depletion Reserves	(9,440,753)	(8,765,640)	7.15%
8	114 Electric Plant Acquisition Adjustments	3,106,285	3,106,285	0.00%
9	115 Accumulated Amortization-Electric Plant Acq. Adj.	(2,062,228)	(2,157,142)	-4.60%
10	117 Gas Stored Underground-Noncurrent	47,175,719	44,881,517	-4.86%
11	**Total Utility Plant**	$1,509,954,140	$745,993,207	-50.59%
12	**Other Property and Investments**			
13	121 Nonutility Property	$2,506,480	$2,749,633	9.70%
14	122 Accumulated Depr. & Amort.-Nonutililty Property	(17,617)	2,384	113.53%
15	123.1 Investments in Subsidiary Companies	358,756,086	444,772,792	23.98%
16	123.* Investments in Colstrip Unit 4 & YNP	195,078,954	55,120,653	-71.74%
17	124 Other Investments	19,082,522	19,545,284	2.43%
18	128 Miscellaneous Special Funds	1,170,816	474,630,855	40438.47%
19	**Total Other Property & Investments**	$576,577,241	$996,821,601	72.89%
20	**Current and Accrued Assets**			
21	131 Cash	$2,519,043	($7,087,137)	-381.34%
22	135 Working Funds	150,378	120,259	-20.03%
23	136 Temporary Cash Investments	98,007	15,500,000	15715.17%
24	141 Notes Receivable	288,038	111,754	-61.20%
25	142 Customer Accounts Receivable	46,384,351	53,519,077	15.38%
26	143 Other Accounts Receivable	7,028,508	4,721,959	-32.82%
27	144 Accumulated Provision for Uncollectible Accounts	(1,043,926)	(1,103,926)	-5.75%
28	145 Notes Receivable-Associated Companies	79,981,743	17,316,970	-78.35%
29	146 Accounts Receivable-Associated Companies	88,018,784	137,430,243	56.14%
30	151 Fuel Stock	942,237	29,919	-96.82%
31	154 Plant Materials and Operating Supplies	16,848,767	9,066,025	-46.19%
32	163 Stores Expense Undistributed	1,191,255	0	-100.00%
33	165 Prepayments	7,997,177	7,282,083	-8.94%
34	171 Interest and Dividends Receivable	1,196,938	2,870,880	139.85%
35	172 Rents Receivable	185,879	102,309	-44.96%
36	173 Accrued Utility Revenues	27,103,026	28,881,980	6.56%
37	**Total Current & Accrued Assets**	$278,890,205	$268,762,395	-3.63%
38	**Deferred Debits**			
39	181 Unamortized Debt Expense	$4,684,108	$4,236,556	-9.55%
40	182 Regulatory Assets	227,539,178	$191,198,312	-15.97%
41	183 Preliminary Survey and Investigation Charges	625,340	625,340	0.00%
42	184 Clearing Accounts	(132,271)	39,911	130.17%
43	185 Temporary Facilities	(25,821)	(9,288)	64.03%
44	186 Miscellaneous Deferred Debits	22,529,275	15,018,157	-33.34%
45	189 Unamortized Loss on Reacquired Debt	8,393,398	7,787,554	-7.22%
46	190 Accumulated Deferred Income Taxes	52,486,150	150,657,017	187.04%
47	191 Unrecovered Purchased Gas Costs	4,646,939	4,021,066	-13.47%
48	**Total Deferred Debits**	$320,746,295	$373,574,625	16.47%
49	**TOTAL ASSETS and OTHER DEBITS**	$2,686,167,880	$2,385,151,827	-11.21%

Sch. 18 cont. **BALANCE SHEET 1/, 2/**

	Account Title	Last Year	This Year	% Change
1	**Liabilities and Other Credits**			
2	**Proprietary Capital**			
3	201 Common Stock Issued	$702,503,756	$703,367,615	0.12%
4	204 Preferred Stock Issued	58,063,500	58,063,500	0.00%
5	207 Premium on capital stock	0	(95,082)	-
6	211 Miscellaneous Paid-In Capital	2,167,132	2,311,971	6.68%
7	213 Discount on Capital Stock	(815,700)	(815,700)	0.00%
8	214 Capital Stock Expense	(93,888)	(93,888)	0.00%
9	215 Appropriated Retained Earnings	6,238,312	6,238,312	0.00%
10	216 Unappropriated Retained Earnings	377,888,556	442,365,355	17.06%
11	217 Reacquired capital stock	0	(144,871,974)	-
12	**Total Proprietary Capital**	$1,145,951,667	$1,066,470,109	-6.94%
13	**Long Term Debt**			
14	221 Bonds	$405,205,000	$350,205,000	-13.57%
15	224 Other Long Term Debt	364,960,700	299,609,179	-17.91%
16	226 Unamortized Discount on Long Term Debt-Debit	(3,708,422)	(3,346,377)	9.76%
17	**Total Long Term Debt**	$766,457,279	$646,467,802	-15.66%
18	**Other Noncurrent Liabilities**			
19	227 Obligations Under Capital Leases-Noncurrent	$525,824	$112,682	-78.57%
20	228.1 Accumulated Provision for Property Insurance	(231,010)	747,760	423.69%
21	228.2 Accumulated Provision for Injuries and Damages	2,228,780	3,068,351	37.67%
22	228.3 Accumulated Provision for Pensions and Benefits	15,037,859	13,578,729	-9.70%
23	228.4 Accumulated Miscellaneous Operating Provisions	265,960	125,687	-52.74%
24	**Total Other Noncurrent Liabilities**	$17,827,412	$17,633,209	-1.09%
25	**Current and Accrued Liabilities**			
26	232 Accounts Payable	$ 21,087,865	$ 23,313,868	10.56%
27	233 Notes Payable to Associated Companies	173,047,150	59,476,916	-65.63%
28	234 Accounts Payable to Associated Companies	36,252,928	92,096,994	154.04%
29	235 Customer Deposits	132,933	356,122	167.90%
30	236 Taxes Accrued	36,372,395	106,844,968	193.75%
31	237 Interest Accrued	13,732,068	10,784,797	-21.46%
32	238 Dividends Declared	21,388,056	19,990,697	-6.53%
33	241 Tax Collections Payable	252,517	254,204	0.67%
34	242 Miscellaneous Current and Accrued Liabilities	27,058,265	11,467,797	-57.62%
35	243 Obligations Under Capital Leases-Current	381,891	910,595	138.44%
36	**Total Current and Accrued Liabilities**	$329,706,068	$325,496,958	-1.28%
37	**Deferred Credits**			
38	252 Customer Advances for Construction	$16,498,385	$17,532,701	6.27%
39	253 Other Deferred Credits	19,682,097	29,918,061	52.01%
40	254 Regulatory Liabilities	9,313,392	12,178,384	30.76%
41	255 Accumulated Deferred Investment Tax Credits	33,819,066	13,329,637	-60.59%
42	257 Unamortized Gain on Reacquired Debt	40,865	31,613	-22.64%
43	281-283 Accumulated Deferred Income Taxes	346,871,649	256,093,352	-26.17%
44	**Total Deferred Credits**	$426,225,454	$329,083,748	-22.79%
45	**TOTAL LIABILITIES and OTHER CREDITS**	$2,686,167,880	$2,385,151,827	-11.21%
46				
47	1/ Includes CMP and Montana Power Capital I; excludes Colstrip Unit 4, Yellowstone National Park and			
48	nonregulated propane.			
49				
50				

NOTES TO FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Basis of Accounting

Our accounting policies conform to generally accepted accounting principles. With respect to utility operations, such policies are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities having jurisdiction.

Use of Estimates

Preparing financial statements requires the use of estimates based on information available. Actual results may differ from our accounting estimates as new events occur or we obtain additional information.

Reclassifications

We have made reclassifications to certain prior-year amounts to make them comparable to the 1999 presentation. These changes had no effect on previously reported results of operations or shareholders' equity.

Financial Statement Presentation

The financial statements are presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. This report differs from generally accepted accounting principles due to FERC requiring the reflection of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards No. 94 "Consolidation of All Majority-Owned Subsidiaries" (SFAS No. 94). SFAS No. 94 requires that all majority-owned subsidiaries be consolidated. The other differences are that comparative statements of retained earnings, cash flows, and net income per share are not presented.

Plant, Property, Depreciation, and Amortization

The following table provides year end balances of the major classifications of property and plant:

	December 31	
	1999	1998
	(Thousands of Dollars)	
Utility Plant		
Electric:		
Generation (including jointly owned)	$ (239,961)	$ 721,995
Transmission	370,166	371,638
Distribution	567,333	544,653
Other	92,292	192,494
Natural Gas:		
Production and storage	71,424	73,115
Transmission	163,968	152,804
Distribution	147,764	146,896
Other	30,693	29,633
Total plant	$ 1,203,679	$ 2,233,228

We capitalize the cost of plant additions and replacements, including an allowance for funds used during construction (AFUDC), of utility plant. We determine the rate used to compute AFUDC in accordance with a formula established by the FERC. This rate averaged 7.1 percent for 1999 and 8.3 percent for 1998. We charge costs of utility depreciable units of property retired, plus costs of removal less salvage, to accumulated depreciation and recognize no gain or loss. We charge maintenance and repairs of plant and property, as well as replacements and renewals of items determined to be less than established units of plant, to operating expenses.

Electric generation plant for 1999 includes a credit of $249,400,000, which represents the excess of sales proceeds over book value, in plant account 102, "Electric Plant Purchased or Sold." For more information on the sale of our electric generating assets, see Note 5, "Sale of Electric Generating Assets."

Included in the plant classifications are utility plant under construction in the amounts of $3,782,000 and $37,966,000 for 1999 and 1998, respectively.

We record provisions for depreciation and depletion at amounts substantially equivalent to calculations made on straight-line and unit-of-production methods by applying various rates based on useful lives of properties determined from engineering studies. As a percentage of the depreciable and depletable utility plant at the beginning of the year, our provisions for depreciation and depletion of utility plant were approximately 3 percent for 1999 and 1998.

Utility Revenue and Expense Recognition

We record operating revenues on the basis of consumption or service rendered. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers but not yet billed at month-end.

Regulatory Assets and Liabilities

For our regulated operations, we follow SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are recognized when included in rates and recovered from or refunded to the customers. The significant regulatory assets we have recorded are discussed below.

In the ratemaking process, tax costs and benefits related to certain temporary differences are recovered in rates on an as paid or "flow-through" basis. SFAS No. 109, "Accounting for Income Taxes," requires that tax assets and liabilities be reflected on the balance sheet on an accrual basis. This timing difference requires that we recognize a regulatory asset for taxes accrued but not yet recovered in rates. That regulatory asset was $57,526,000 and $119,080,000 as of December 31, 1999 and 1998, respectively.

In August 1985, the Montana Public Service Commission (PSC) issued an order allowing us to recover deferred carrying charges and depreciation expenses over the remaining life of Colstrip Unit 3. These recoveries compensated us for unrecovered costs of our investment for the period from January 10, 1984, to August 29, 1985, when we placed the plant in service. We were amortizing this asset to expense, and recovering in rates, $1,831,000 per year. At December 31, 1999 and 1998, the unamortized amounts were $38,494,000 and $40,325,000, respectively.

We also include costs related to our Demand Side Management (DSM) programs in other regulatory assets. These amounts were $28,378,000 and $33,353,000 for 1999 and 1998, respectively. These costs are in rate base and we were amortizing them to income over a 10-year period.

Competitive transition charges, which relate to natural gas properties that were removed from regulation on November 1, 1997, are being recovered through rates over 15 years. The unamortized balances at December 31, 1999 and 1998, were $53,768,000 and $56,059,000, respectively.

Certain other costs are being amortized currently or are subject to regulatory confirmation in future ratemaking proceedings.

Changes in regulation or changes in the competitive environment could result in our not meeting the criteria of SFAS No. 71. If we were to discontinue application of SFAS No. 71 for some or all of our regulated operations, we would have to eliminate the related regulatory assets and liabilities from the balance sheet and include the associated expenses and credits in income in the period when the discontinuation occurred, unless recovery of those costs was provided through rates charged to those customers in portions of the business that were to remain regulated.

With the sale of the generating assets, it is our position that any regulatory assets and liabilities related to electric supply should be recovered from sales proceeds in excess of book value. For further information on the effects of the sale of our electric generating assets, see Note 5, "Sale of Electric Generating Assets." For further information on the removal in 1997 of our natural gas production assets from rate base, see Note 4, "Deregulation and Regulatory Matters."

<u>Cash and Cash Equivalents</u>

We consider all liquid investments with original maturities of three months or less as cash equivalents, and investments with original maturities over three months and up to one year as temporary investments. At December 31, 1999, all of our investments were available for sale, and their fair value approximated the value reported on the balance sheet.

<u>Storm Damage and Environmental Remediation Costs</u>

When losses from costs of storm damage and environmental remediation obligations for our utility operations are probable and reasonably estimable, we charge these costs against established, approved operating reserves. We consider the reserves adequate. The reserves balance at December 31, 1999, was approximately $11,200,000, and at December 31, 1998, was approximately $9,300,000. We have included these reserves in Other Noncurrent Liabilities on the balance sheet.

<u>Income Taxes</u>

We defer income taxes to provide for the temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. For further information on income taxes, see "Regulatory Assets and Liabilities" in this Note 1 and also Note 6, "Income Tax Expense."

<u>Asset Impairment</u>

In accordance with SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," we periodically review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. In 1999, the Company recorded an expense of $4,100,000 in accordance with SFAS No. 121.

<u>Comprehensive Income</u>

FASB defines comprehensive income as all changes to the equity of a business enterprise during a period, except for those resulting from transactions with owners. For example, dividend distributions are excepted. Comprehensive income consists of net income and other comprehensive income. Net income includes such items as income from continuing operations, discontinued operations, extraordinary items, and cumulative effects of changes in accounting principle. Other comprehensive income includes foreign currency translations, adjustments of minimum pension liability, and unrealized gains and losses on certain investments in debt and equity securities.

For the years ended December 31, 1999 and 1998, our only item of other comprehensive income was foreign currency translation adjustments of the assets and liabilities of our foreign subsidiaries. These adjustments resulted in increases to retained earnings of $3,058,000 in 1999, and decreases to retained earnings of $7,363,000 in 1998. No current income tax effects resulted from the adjustments, nor will there be any net income effects until we sell a foreign subsidiary.

Most of the 1998 adjustment was the result of transferring a Canadian natural gas production company from utility to nonutility operations. Until November 1, 1997, the property, plant, and equipment (PP&E) of that company was included in our natural gas utility rate base at its original U.S. dollar value. After that company was transferred to nonutility operations, we were no longer required to state its PP&E at original U.S. dollar value, but were required instead to convert its PP&E at the foreign exchange rate in effect at the balance sheet date. At the time of the transfer, the Canadian-U.S. exchange rate was considerably lower than the rates used to convert most of the original U.S. dollar values of that company's PP&E. Consequently, the adjustment from original to current U.S. dollar value decreased other comprehensive income approximately $5,100,000 in 1998.

Fair Value of Significant Financial Instruments

	1999		1998	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of Dollars			
Assets:				
Other significant investments	$ 19,509	$ 19,509	$ 19,044	$ 19,044
Liabilities:				
Long-term debt (including due within one year)	$ 646,468	$ 628,313	$ 766,457	$ 807,509

The following methods and assumptions were used to estimate fair value:

- Other investments - The carrying value of the investments approximates fair value since the investments have short maturities or the carrying value equals their cash surrender value.
- Long-term debt - We estimated the fair value of long-term debt by using quoted market rates for the same or similar instruments. Where quotes were not available, we estimated fair value by discounting expected future cash flows using year-end incremental borrowing rates.

NOTE 2 – CONTINGENCIES:

Kerr Project

A FERC order that preceded our sale of the Kerr Project to PPL Montana required us to implement a plan to mitigate the effect of the Kerr Project operations on fish, wildlife, and habitat. To implement this plan, we were required to make payments of approximately $135,000,000 between 1985 and 2020, the term during which we would have been the licensee. The net present value of the total payments, assuming a 9.5 percent annual discount rate, was approximately $57,000,000, an amount we recognized as license costs in plant and long-term debt on the Consolidated Balance Sheet in 1997. In the sale of the Kerr Project, PPL Montana assumed the obligation to make post-closing license compliance payments.

In December 1998 and January 1999, we asked the United States Court of Appeals for the District of Columbia Circuit to review FERC's orders and the United States Department of Interior's conditions contained in them. On September 17, 1999, the court granted the motion of the parties and intervenors to hold up the appeal pending settlement efforts. In December 1999, we, along with PPL Montana, the United States Department of the Interior, the Confederated Salish and Kootenai Tribes (the Tribes), and Trout Unlimited, in a court-ordered mediation, agreed in principle to settle this litigation.

A Statement of Agreement containing the principles for settlement of the disputes underlying the appeals was developed in December 1999. It provides that its terms are binding against all parties, with the understanding that the signatory parties will jointly draft additional documents as necessary to establish the terms of the settlement in detail. The parties have drafted these documents, and we have paid our settlement payment under the Statement of Agreement into an escrow account. If FERC approves, in a final non-appealable order, the settlement terms as reflected in proposed license amendments, we will dismiss the petitions in the court of appeals, and the escrow agent will release the payments to the Tribes. In addition, we will transfer to the Tribes 669 acres of land we own on the Flathead Indian Reservation. If FERC does not approve the proposed license amendments in the form agreed to by the parties, or if, as a result of the appeal of a FERC order, that order is not final after a specified period, the money will be returned to us, and the litigation will resume. The settlement, subject to the conditions described above, substantially reduces our obligation to pay for fish, wildlife, and habitat mitigation assigned to the pre-closing period in the sale of the Kerr Project.

In April 2000, PPL Montana and the Tribes, as co-licensees, filed proposed license amendments with FERC to effect the settlement described above. We supported these proposed license amendments. FERC is reviewing the filing, but we do not expect a decision until late 2000 or early 2001.

Miscellaneous

We are party to various other legal claims, actions and complaints arising in the ordinary course of business. We do not expect the conclusion of any of these matters to have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

NOTE 3 - COMMITMENTS:

Purchase Commitments

Electric Utility

The Public Utilities Regulatory Policy Act (PURPA) mandates a public utility to purchase power from Qualifying Facilities (QFs) at a rate equal to what it would pay to generate or purchase power. These QFs are power production or co-generation facilities that meet size, fuel use, ownership criteria, and operating and efficiency standards specified by PURPA. The electric utility has 15 long-term QF contracts with expiration terms between 2003 and 2031 that require us to make payments for energy capacity and energy received at prices currently above market. Three contracts account for 96 percent of the 101 MWs of capacity provided by these facilities. Montana's Electric Industry Restructuring and Customer Choice Act (Electric Act) designates the above-market portion of the QF costs as Competitive

Transition Costs (CTCs) and allows for their recovery. For more information about CTCs, see Note 4 - "Deregulation and Regulatory Matters."

The sales agreement with PPL Montana included the assignment of our contract with Basin Electric Power Cooperative (Basin) to PPL Montana. That contract committed us to purchase 98 MWs of seasonal capacity from Basin from 1994 to November 2010, at prices above current and projected market prices. However, Basin did not release us from that contract. Consequently, if PPL Montana were to default, Basin could hold us liable to perform according to the terms of the contract. Because we believe that PPL Montana will not default, we do not consider this contract our unconditional purchase obligation.

The sales agreement with PPL Montana also included two Wholesale Transition Service Agreements (WTSAs), effective December 17, 1999. These agreements enable us to fulfill our obligation to supply power until July 2002 to those customers who will not have chosen another supplier. One agreement commits us to purchase 200 MWs per hour through December 2001, and the other agreement to purchase through June 2002 any power requirements remaining after having received power through the first WTSA, QFs, and Milltown Dam. Both agreements price the power sold at a market index, with a monthly floor and an annual cap. Assuming a 7.23 percent discount rate and current load forecasts, the net present value of the power purchased under the WTSAs may range from $94,000,000 to $104,000,000 for 2000, $61,000,000 to $69,000,000 for 2001, and $24,000,000 to $27,000,000 for 2002. In conformity with SFAS No. 47 - "Disclosure of Long-Term Obligations," we use the lower estimate in the tables below.

Natural Gas Utility

The natural gas utility entered into take-or-pay contracts with Montana natural gas producers to provide adequate supplies of natural gas for our utility customers. We currently have six such contracts, with expirations between 2000 and 2006. If we can supply customers with less expensive natural gas, we purchase the minimum required by the take-or-pay contracts. The cost of purchases through take-or-pay contracts is part of those costs submitted to the PSC for recovery in future rates. Currently, the natural gas utility is only entering into one-year take-or-pay contracts, because of the uncertainty about the number and timing of customers who will choose another natural gas supplier under Montana's Natural Gas Utility Restructuring and Customer Choice Act (Natural Gas Act).

Total payments under these contracts for the prior two years were:

	Thousands of Dollars		
	Electric	Natural Gas	Total
1998	$ 50,611	$ 3,508	$ 54,119
1999	61,274	4,069	65,343

Under the above agreements, the present value of future minimum payments, at a discount rate of 7.23 percent, is:

	Thousands of Dollars		
	Electric	Natural Gas	Total
2000	$ 102,050	$ 4,023	$ 106,073
2001	69,752	2,312	72,064
2002	32,052	1,945	33,997
2003	7,543	317	7,860
2004	7,317	280	7,597
Remainder	106,074	502	106,576
	$ 324,788	$ 9,379	$ 334,167

Sales Commitments

We entered into a contract to sell electricity to an industrial customer at terms that include a fixed price for a portion of the power delivered and an index-based price for another portion through December 2002. For 2003 and 2004, we sell all power to our customer at an index-based price. Since the sale of our electric generating assets, we have been supplying our customer with power purchased through an index-based contract that remains effective through July 2001. Our industrial customer has given us usage estimates that do not exceed the amount of electricity that we are committed to purchase.

Because the price of power under the index-based purchase contract could exceed the price of power under the fixed-price portion of our sales contract, we are subject to commodity price risk. Due to uncertainties relating to the supply requirements of the sales contract and uncertainties surrounding various arrangements that would allow us to serve the contractual demand, we cannot determine at this time the effects that this contract ultimately may have on our consolidated financial position, results of operations, or cash flows. We will continue to examine our options and take steps to mitigate the commodity price risk resulting from this contract.

Lease Commitments

There are no material minimum operating lease payments. Capitalized leases are also not material and are included in other long-term debt.

Rental expense for the prior two years was $22,139,000 and $19,531,000 for 1999 and 1998, respectively. We have restated the previously reported 1998 rental expense of $31,589,650, because it included costs related to Colstrip Unit 4, which is not subject to PSC authority.

NOTE 4 – DEREGULATION AND REGULATORY MATTERS:

Deregulation

The electric and natural gas utility businesses are transitioning to a competitive market in which energy commodity products and related services are sold directly to wholesale and retail customers. Montana's Electric Act, passed in 1997, provides that all customers will be able to choose their electric supplier by July 1, 2002. Montana's Natural Gas Act, also passed in 1997, provides that a utility may voluntarily offer its customers choice of natural gas suppliers and provide open access. Since natural gas restructuring is voluntary, no deadline for choice exists.

Electric

Through December 1999, approximately 900 electric customers representing more than 1,300 accounts crossing all customer sectors – or approximately 27 percent of our pre-choice electric load – have moved to competitive supply since the inception of customer choice on July 1, 1998. Residential customers were eligible to move to choice during the fourth quarter of 1999. However, the majority of the load associated with our pre-choice electric customers that moved to other suppliers was industrial and large commercial customers.

As required by the Electric Act, we filed a comprehensive transition plan with the PSC in July 1997. Initial hearings on the filing began in April 1998, and the issues were separated into two groups: Tier I and Tier II.

Tier I issues dealt with:

- Accounting orders;
- Customer choice for the large industrial customer group;
- Pilot programs for the remaining customers; and
- A code of conduct.

Tier II issues address:

- The recovery and treatment of the QF power-purchase contract costs, which are above-market costs;
- Regulatory assets associated with our electric generating business; and
- A review of our electric generating assets sale, including the treatment of sale proceeds in excess of the book value of the assets and other generation-related transition costs.

In June 1998, the PSC rendered a decision on the Tier I issues, and on July 1, 1999, we filed a case with the PSC to resolve the Tier II issues. We will update our Tier II filing because of the closing of the sale of our electric generating assets, but we do not expect an order from the PSC until late 2000.

With deregulation and the resulting competition, certain generation and power supply-related costs become stranded, or unrecoverable, absent recovery from customers as a transition cost. CTCs are generation and power supply-related costs that we incurred in the regulated environment with the expectation that we would recover these costs from our customers well into the future. Included within the CTCs are the following: (1) generation-related regulatory assets, (2) utility owned generation and other purchased-power contracts, and (3) our purchase-power contracts with the QFs. We are evaluating options with respect to the QF contracts to minimize costs and are working on a number of potential buy-out agreements. The owners of the QF contracts must approve any agreements related to the contracts. In addition, the PSC must approve future cost recovery. The Electric Act allows us to issue transition bonds to refinance CTCs.

In an order issued as part of its consideration of our transition plan, the PSC concluded that the Electric Act does not provide for tracking mechanisms to ensure fair and accurate recovery of out-of-market QF costs and certain other transition costs, but that transition costs must be mitigated and determined as a final matter in the transition filing. Not agreeing with that interpretation of the Electric Act, we initiated litigation in Montana District Court in Butte seeking reversal of a PSC decision regarding our ability to use tracking mechanisms. The PSC also concluded that the Electric Act authorized a rate cap during the transition period that ends July 1, 2002. Again not agreeing with the PSC, we sought court clarification on whether the Electric Act authorized a rate freeze or a rate cap.

On May 12, 2000, the Montana District Court ruled that tracking our actual stranded, or out-of-market, electric transition costs, relating mainly to qualifying facilities, was appropriate to ensure fair and accurate recovery of these costs. The district court also ruled that the Electric Act authorized a rate cap, in which rates cannot be more, but can be less than those in effect at July 1, 1998.

Natural Gas

Through December 1999, approximately 240 natural gas customers with annual consumption of 5,000 dekatherms or more – or 52 percent of our pre-choice natural gas supply load – have chosen alternate suppliers since the transition to a competitive natural gas environment began in 1991.

In accordance with a 1997 PSC order, we transferred substantially all of our natural gas utility's production assets to unregulated affiliates at an agreed-upon amount, which was approximately $33,600,000 lower than the book value of the assets. As a component of competitive transition costs (CTCs), the PSC is allowing us to recover from our transmission and distribution customers (a) this $33,600,000 difference between transfer value and book value, and (b) approximately $25,400,000 of existing regulatory assets related to the natural gas production assets. In 1998, we issued $62,700,000 in transition bonds to refinance the CTCs for the benefit of the customers. The transition bonds will be retired over 15 years through rates revenues established in accordance with Montana's Natural Gas Act. The amortization of the assets is proportionate to the repayment of principal on the bonds resulting in no net income statement impact. The transition plan also includes a fixed-price supply contract until July 1, 2002, between our unregulated gas supply operations and our regulated distribution operations to serve the remaining customers who have not chosen other suppliers.

Regulatory Matters

Milltown Dam and our electric transmission operations remain subject to PSC and FERC regulation, and the PSC regulates our electric distribution operations.

As a Hinshaw pipeline (interstate pipeline exempt from FERC jurisdiction), our natural gas transportation pipelines are not subject to FERC jurisdiction. However, we conduct interstate transportation, subject to FERC jurisdiction through an exception of our Hinshaw status. Presently, FERC has allowed the PSC to set rates for this interstate service. Our natural gas distribution and storage operations remain subject to PSC regulation. In addition, the Alberta Energy and Utilities Board, the National Energy Board of Canada, and the United States Department of Energy all must approve the importing of Canadian natural gas.

As a public utility, we also are subject to PSC jurisdiction when we issue, assume, or guarantee securities, or when we create liens on our properties.

Electric

The Electric Act established a rate freeze for all electric customers, meaning that transmission and distribution rates cannot be increased until July 1, 2000. In January 2000, we filed a voluntary rate reduction with the PSC for approximately $16,700,000 annually, which we would implement by using the generation sales proceeds in excess of the book value of the generation assets sold. The reduction is effective on an interim basis pending the PSC review of our Tier II filing. For additional information on the generation sale, see Note 5, "Sale of Electric Generating Assets."

Natural Gas

On August 12, 1999, we filed a natural gas rate docket with the PSC requesting, among other matters, an increase in annual revenues of $15,400,000, with a proposed interim increase of $11,500,000. The filing also proposes:

- An alternative rate plan;
- "Trackers" to reflect property taxes and replacement facilities in rates on a more timely basis;
- A change in the allocation of costs to customer classes; and
- Rate-design changes that include recovery of distribution charges through a fixed monthly system charge.

On December 9, 1999, the PSC approved an interim increase of $7,600,000 regarding the natural gas rate docket discussed above. A final PSC order that became effective on April 1, 2000, approved an additional increase of $2,800,000.

On November 17, 1999, we filed a second natural gas rate docket with the PSC requesting recovery of costs associated with tracking gas costs annually. Approval by the PSC would result in an increase in annual revenues of $4,800,000. On December 9, 1999, the PSC approved an interim increase for this amount until we receive the final order, which we expect by mid-2000.

NOTE 5 – SALE OF ELECTRIC GENERATING ASSETS:

<u>Assets Sold</u>

On December 17, 1999, in accordance with the Asset Purchase Agreement (Agreement), we sold to PPL Montana substantially all of our electric generating assets, related contracts, and associated transmission assets totaling less than 40 miles. This included 11 of our 12 hydroelectric facilities; a storage reservoir; a coal-fired thermal generating plant at Billings, Montana; all of our interest in three coal-fired thermal generating plants at Colstrip, Montana; and other related assets, including inventories associated with the power plants. The total gross capacity of the hydroelectric facilities and coal-fired thermal generating plants sold to PPL Montana was 1,314.5 MWs.

The sale did not include the Milltown Dam near Missoula, Montana (gross capacity of 3 MWs) or any of our QF purchase-power contracts. It also did not include our leased share of the Colstrip Unit 4 generation or transmission assets.

In the sale of these assets, we generally retained all pre-closing obligations, and PPL Montana assumed all post-closing obligations. However, with respect to environmental liabilities, PPL Montana assumed all pre-closing (subject to the indemnification provisions discussed below) and post-closing environmental liabilities associated with the purchased assets, with three exceptions for pre-closing liabilities:

- Payment of fines or penalties imposed by regulatory authorities related to pre-closing activity;
- Liability for pre-closing "off-site" activity, such as transportation, disposal, or storage of hazardous material; and
- Remediation costs of any silts behind the Thompson Falls Dam relating to pre-closing activity.

We agreed to indemnify PPL Montana from losses arising from pre-closing environmental conditions. The indemnity for required remediation of pre-closing conditions, whether known or unknown at the closing, is limited to:

- 50 percent of the loss. Our share of this indemnity obligation at the Colstrip Project is limited to our pro rata share of this 50 percent based on our pre-sale ownership share.

- A two-year period after closing for unknown conditions. The indemnity for required remediation of pre-closing conditions known at the time of the closing continues indefinitely.

- An aggregated amount no greater than 10 percent of the purchase price paid for the assets.

We do not expect this indemnity obligation to have a materially adverse effect on our financial position, results of our operations, or cash flows. We have accrued the estimated amount of the potential liability associated with these retained obligations.

Cash Proceeds

The cash proceeds received for the sale of the assets, including prorated adjustments for such items as inventory and property taxes, was approximately $758,600,000 (including approximately $1,000,000 received in 2000). Our transaction costs to complete the sale amounted to approximately $12,100,000.

At December 31, 1999, we recorded approximately $219,700,000 as net proceeds in excess of the book value, based on net cash proceeds of $746,500,000 less (1) approximately $497,300,000 book value of the assets sold and (2) approximately $29,500,000 of previously flowed-through tax benefits. We also recorded an income tax liability of approximately $164,100,000 based on the net cash proceeds less the tax basis of the assets sold.

As part of our Tier II transition filing, we plan to deduct from the regulatory liabilities approximately $39,300,000 of other generation-related transition costs and approximately $64,600,000 of regulatory asset transition costs. The other generation-related transition costs consist mainly of stranded SG&A costs and costs to retire debt. The regulatory asset transition costs consist mainly of capitalized conservation costs and carrying charges associated with Colstrip Unit 3.

PPL Montana also agreed to purchase 1,058 MWs of additional gross capacity in Colstrip, Montana from Puget Sound Energy, Inc. and Portland General Electric Company. Pursuant to the terms of the Agreement with PPL Montana, we would receive an additional $152,000,000 from PPL Montana, for added value, if Puget and Portland General both close their transactions. The added value would arise from the controlling interest in Colstrip Units that PPL Montana would hold, as a result of the combination of our former assets with those of Puget and Portland General. However, if only one of Puget or Portland General – but not both – closes its respective transaction, we will receive only $117,000,000 from PPL Montana rather than $152,000,000. If neither Puget or Portland General closes its transaction, the Agreement provides that, subject to the receipt of required regulatory approvals, PPL Montana will purchase the portion of our 500-kilovolt transmission system not associated with Colstrip Unit 4. Our sales proceeds from PPL Montana for these properties would be $97,100,000.

In February 2000, the Oregon Public Utility Commission indicated that it would deny Portland General's request to sell its ownership interest in Colstrilp Units 3 and 4 to PPL Montana.

Effect On 1999 Earnings

The asset sale positively affected our electric utility's 1999 earnings through the reversal of approximately $3,000,000 (after taxes) in interest expense recorded in prior years relating to Kerr Project liabilities and through recognition of approximately $10,000,000 in investment tax credits.

Use of Proceeds

We have used a portion of the net cash proceeds received (less the sale proceeds in excess of the book value) for the following general corporate purposes:

- Funding utility and nonutility projects, including those involving expansion of Touch America;
- Reducing debt; and
- Purchasing shares of our common stock.

For additional information on the purchase of shares of common stock and the reduction of debt, see Note 7, "Common Stock," and Note 10, "Long-Term Debt."

NOTE 6 - INCOME TAX EXPENSE:

Income before income taxes was as follows:

	Year Ended December 1999	Year Ended December 1998
	(Thousands of Dollars)	
United States	$ 76,861	$ 81,708
Canada	104	99
	$ 76,965	$ 81,807

The provision for income taxes differs from the amount of income tax that would result by applying the applicable United States statutory federal income tax rate to pretax income because of the following differences:

	December 31 1999	December 31 1998
	(Thousands of Dollars)	
Computed "expected" income tax expense	$ 26,938	$ 28,633
Adjustments for the tax effects of:		
General business credits	(20,489)	(1,363)
State income tax - net	1,219	3,975
Reversal of excess of utility income tax depreciation over financial accounting depreciation on utility plant additions	5,318	2,784
Other	(1,056)	(7,504)
Actual income taxes	$ 11,930	$ 26,525

Income tax expense as shown in the Statement of Income consists of the following components:

	Year Ended December 31	
	1999	1998
	(Thousands of Dollars)	
Current:		
United States	$ 157,950	$ 22,816
Canada	63	63
State	31,905	7,068
	189,918	29,947
Deferred:		
United States	$ (149,979)	$ (2,765)
Canada	-	-
State	(28,009)	(659)
	(177,988)	(3,424)
	$ 11,930	$ 26,523

Deferred tax liabilities (assets) are comprised of the following:

	December 31	
	1999	1998
	(Thousands of Dollars)	
Plant related	$ 216,115	$ 312,976
Other	39,812	33,745
Gross deferred tax liabilities	255,927	346,721
Amortization of gain on sale/leaseback	(4,681)	(5,441)
Investment tax credit amortization	(14,056)	(21,833)
Other	(131,754)	(25,061)
Gross deferred tax assets	(150,491)	(52,335)
Net deferred tax liabilities	$ 105,436	$ 294,386

The change in net deferred tax liabilities differs from current year deferred tax expense as a result of the following:

	(Thousands of Dollars)
Increase (decrease) in total deferred tax liabilities (assets)	$ (188,950)
Regulatory assets related to income taxes	61,537
Amortization of investment tax credits	(20,489)
Balance sheet only – generation sale regulatory asset	(29,696)
Other	(390)
Deferred tax expense	$ (177,988)

NOTE 7 - COMMON STOCK:

Stock Split

On June 22, 1999, the Board of Directors approved a two-for-one split of our outstanding common stock. As a result of the split, which was effective August 6, 1999, for all shareholders of record on July 16, 1999, 55,099,015 outstanding shares of common stock were converted to 110,198,030 outstanding shares of common stock. We have retroactively applied the split to all periods presented.

Share Repurchase Plan

In 1998, the Board of Directors authorized a share repurchase program over the next five years to repurchase up to 20,000,000 shares (approximately 18 percent of our then outstanding common stock) on the open market or in privately negotiated transactions. As of December 31, 1999, we had 105,536,873 common shares outstanding. The number of shares to be purchased and the timing of the purchases will be based on the level of cash balances, general business conditions, and other factors, including alternative investment opportunities.

As a result of this authorization, we entered into a Forward Equity Acquisition Transaction (FEAT) program with a bank that committed to purchase on our behalf up to 5,000,000 shares, but not to exceed $125,000,000. On November 12, 1999, we amended the FEAT program to increase the monetary limit to $200,000,000. The expiration date of the program is October 31, 2000. Until that date, when all transactions must be settled, we can elect to fully or partially settle either on a full physical (cash) or a net share basis. A full physical settlement would be the purchase of shares from the bank for cash at the bank's average purchase price, including interest costs less dividends. A net share settlement would be the exchange of shares between the parties so that the bank receives shares with value equivalent to its original purchase price, including interest costs less dividends. Only at the time that the transactions are settled can our capital or outstanding stock be affected, and settlement has no effect on results of operations.

Since the FEAT program began and through December 23, 1999, the bank had acquired for us 4,682,100 shares of our stock. The purchase of these shares averaged approximately $30.94 per share and ranged from $27.05 per share to $33.52 per share for a total cost of $144,872,000. On December 23, 1999, we used proceeds from the sale of our generation assets to effect a full physical settlement for that amount. We have reflected the shares purchased as treasury stock on the Comparative Balance Sheet. As of December 31, 1999, no additional shares had been acquired under the program.

Shareholder Protection Rights Plan

We have a Shareholder Protection Rights Plan (SPRP) that provides one preferred share purchase right on each outstanding common share. Each purchase right entitles the registered holder, upon the occurrence of certain events, to purchase from us one one-hundredth of a share of Participating Preferred Shares, A Series, without par value. If it should become exercisable, each purchase right would have economic terms similar to one share of common stock. The purchase rights trade with the underlying shares and will, except under certain circumstances described in the SPRP, expire on June 6, 2009, unless redeemed earlier or exchanged by us.

Dividend Reinvestment and Stock Purchase Plan

Our Dividend Reinvestment and Stock Purchase Plan permits participants to: (a) Acquire additional shares of common stock through the reinvestment of dividends on all or any specified number of common and/or preferred shares registered in their own names, or through optional cash payments of up to $60,000 per year; and (b) Deposit common and preferred stock certificates into their Plan accounts for safekeeping. It also allows for other interested investors (residents of certain states) to make initial purchases of common shares with a minimum of $100 and a maximum of $60,000 per year.

Retirement Savings Plan

We have a Retirement Savings Plan that covers all regular eligible employees. We contribute, on behalf of the employee, a matching percentage of the amount contributed to the Plan by the employee. In 1990, we borrowed $40,000,000 at an interest rate of 9.2 percent to be repaid in equal annual installments over 15 years. The proceeds of the loan were lent on similar terms to the Plan Trustee, which used the proceeds to purchase 3,844,594 shares of our common stock. Shares acquired with loan proceeds are allocated to Plan participants. The loan, which is reflected as long-term debt, is offset by a similar amount in common shareholders' equity as unallocated stock. Our contributions plus the dividends on the shares held under the Plan are used to meet principal and interest payments on the loan with the Plan Trustee. As principal payments on the loan are made, long-term debt and the offset in common shareholders' equity are both reduced. At December 31, 1999, 2,500,678 shares had been allocated to the participants' accounts. We recognize expense for the Plan using the Shares Allocated Method, and the pretax expense was $3,768,000 and $3,801,000 for 1999 and 1998, respectively.

Long-Tem Incentive Plan

Under the Long-Term Incentive Plan, we have issued options to our employees. Options issued to employees are not reflected in balance sheet accounts until exercised, at which time: (1) Authorized but unissued shares are issued to the employee, (2) The capital stock account is credited with the proceeds, and (3) No charges or credits to income are made.

Options were granted at the average of the high and low prices as reported on the New York Stock Exchange composite tape on the date granted and expire ten years from that date.

Option activity is summarized below:

	1999		1998	
	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price
Outstanding, beginning of year	2,548,094	$ 22.71	1,081,330	$ 11.00
Granted	919,510	32.14	2,234,658	24.50
Exercised	88,857	10.83	702,562	11.25
Cancelled	98,422	24.08	65,332	13.47
Outstanding, end of year	3,280,325	$ 25.63	2,548,094	$ 22.71

Shares under option at December 31, 1999, are summarized below:

	Options Outstanding				
	Options Exercisable				
Exercise Price Range	Shares	Wtd Avg Exercise Price	Wtd Avg Exercise Life	Shares	Wtd Avg Exercise Price
$10.81 to $11.31	271,779	$ 11.06	5 years	271,779	$ 11.06
$18.00 to $19.17	488,000	18.56	8 years	12,000	18.00
$26.53 to $27.56	1,981,814	26.73	9 years	-	-
$35.36	538,732	35.36	10 years	-	-
	3,280,325			283,779	-

As permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," we have elected to follow Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25) and related interpretations in accounting for our employee stock options. Under APB 25, because the exercise price of the employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized. Disclosure of pro forma information regarding net income and earnings per share is required by SFAS No. 123. This information has been determined as if we had accounted for our employee stock options under the fair value method of that statement. The weighted-average fair value of options granted in 1999 and 1998 was $7.03 and $7.12 per share, respectively. We employed the binomial option-pricing model to estimate the fair value of each option grant on the date of grant. We used the following weighted-average assumptions for grants in 1999 and 1998, respectively: (1) Risk-free interest rate of 6.35 percent and 5.08 percent; (2) Expected life of 9.8 and 10 years; (3) Expected volatility of 24.92 percent and 19.34 percent; and (4) A dividend yield of 5.97 percent and 6.51 percent. Had we elected to use SFAS No. 123, compensation expense would have increased $5,280,000 in 1999 and $795,000 in 1998. The 1999 pro forma net income would be $143,456,000 with basic earnings per common share of $1.31 and diluted earnings per common share of $1.30. The 1998 compensation expense effects on net income and earnings per share are not significant.

NOTE 8 - PREFERRED STOCK:

We have 5,000,000 authorized shares of preferred stock. We cannot declare or pay dividends on our common stock while we have not either declared and set apart cumulative dividends or paid dividends on any of our preferred stock.

Our preferred stock is in three series as detailed in the following table:

Stated and Liquidation		Shares Issued and Outstanding		Thousands of Dollars	
Series	Price*	1999	1998	1999	1998
$ 6.875	$ 100	360,800	360,800	$ 36,080	$ 36,080
6.00	100	159,589	159,589	15,959	15,959
4.20	100	60,000	60,000	6,025	6,025
Discount		-	-	(410)	(410)
		580,389	580,389	$ 57,654	$ 57,654

*Plus accumulated dividends.

We have the option of redeeming our preferred stock with the consent or affirmative vote of the holders of a majority of the common shares on 30 days notice at $110 per share for our $6.00 series and $103 per share for our $4.20 series, plus accumulated dividends. Our $6.875 series is redeemable in whole or in part, at any time on or after November 1, 2003, for a price beginning at $103.438 per share, which decreases annually through October 2013. After that time, the redemption price is $100 per share.

NOTE 9 - COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST:

We established Montana Power Capital I (Trust) as a wholly owned business trust to issue common and preferred securities and hold Junior Subordinated Deferrable Interest Debentures (Subordinated Debentures) that we issue. At December 31, 1999 and 1998, the Trust has issued 2,600,000 units of 8.45 percent Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). Holders of the QUIPS are entitled to receive quarterly distributions at an annual rate of 8.45 percent of the liquidation preference value of $25 per security. The sole asset of the Trust is $67,000,000 of our Subordinated Debentures, 8.45 percent Series due 2036. The Trust will use interest payments received on the Subordinated Debentures that it holds to make the quarterly cash distributions on the QUIPS. The $65,000,000 liquidation value of the QUIPS is included with Other Long-Term Debt on the balance sheet.

On or after November 6, 2001, we can wholly redeem the Subordinated Debentures at any time, or partially redeem the Subordinated Debentures from time to time. We also can wholly redeem the Subordinated Debentures if certain events occur before that time. Upon repayment of the Subordinated Debentures at maturity or early redemption, the Trust Securities must be redeemed. In addition, we can terminate the Trust at any time and cause the pro rata distribution of the Subordinated Debentures to the holders of the Trust Securities.

Besides our obligations under the Subordinated Debentures, we have agreed to certain Back-up Undertakings. We have guaranteed, on a subordinated basis, payment of distributions on the Trust Securities, to the extent the Trust has funds available to pay such distributions, and we have agreed to pay all of the expenses of the Trust. Considered together with the Subordinated Debentures, the Back-up Undertakings constitute a full and unconditional guarantee of the Trust's obligations under the QUIPS. We are the owner of all the common securities of the Trust, which constitute 3 percent of the aggregate liquidation amount of all the Trust Securities.

NOTE 10 - LONG-TERM DEBT:

The Mortgage and Deed of Trust (Mortgage) imposes a first mortgage lien on all physical properties owned, exclusive of subsidiary company assets and certain property and assets specifically excepted. The obligations collateralized are First Mortgage Bonds, including those First Mortgage Bonds designated as Secured Medium-Term Notes and those securing Pollution Control Revenue Bonds.

Long-term debt consists of the following:

	December 31	
	1999	1998
	(Thousands of Dollars)	
First Mortgage Bonds:		
7.7% series, due 1999	$ -	$ 55,000
7 1/2% series, due 2001	25,000	25,000
7% series, due 2005	50,000	50,000
8 1/4% series, due 2007	55,000	55,000
8.95% series, due 2022	50,000	50,000
Secured Medium-Term Notes –		
maturing 2000-2025 7.20% - 8.11%	88,000	88,000
Pollution Control Revenue Bonds:		
City of Forsyth, Montana		
6 1/8% series, due 2023	90,205	90,205
5.9% series, due 2023	80,000	80,000
ESOP Notes Payable – 9.2%, due 2004	19,431	22,392
Unsecured Medium-Term Notes:		
Series A – maturing 1999 – 2022 8.68% - 8.9%	17,000	19,500
Series B – maturing 2001 – 2026 6.37% - 7.96%	100,000	115,000
8.45% QUIPS	65,000	65,000
Other	10,178	55,069
Unamortized Discount and Premium	(3,346)	(3,709)
	$646,468	$766,457

On February 1, 1999, we used the proceeds from asset-backed securities issued by a wholly owned subsidiary to retire at maturity $55,000,000 of our 7.7 percent First Mortgage Bonds.

The electric and natural gas legislation discussed in Note 4, "Deregulation and Regulatory Matters," authorized the issuance of transition bonds. These securitization bonds involve the issuance of a non-recourse debt instrument. The bonds are repaid through, and secured by, a specified component of future revenues meant to recover the regulatory assets, thereby reducing the credit risk of the securities. This specific component of revenues is referred to as a CTC. An April 1998 PSC Financing Order related to natural gas approved the issuance of up to $65,000,000 of such bonds. In December 1998, we issued $62,700,000 of 6.2 percent bonds. We will retire the bonds at six-month intervals from September 15, 1999, through March 15, 2012. Retirements are in varying amounts depending on revenues collected from customers. We established an SPE, which is a wholly owned subsidiary, to issue the bonds. At December 31, 1999, approximately $61,015,000 was outstanding, of which approximately $2,600,000 was classified as due within one year on the balance sheet.

Although the bonds were issued by an SPE and are without recourse to our general credit, the bonds are shown as debt on the balance sheet. Similarly, the right to receive the revenues pledged to secure the bonds is a specific right of the SPE and not of Montana Power's. However, as a wholly owned subsidiary, the SPE's revenues and expenses are shown as revenues and expenses on the Statement of Income. Due to the regulatory mechanism for recognizing the operations of the SPE, including the amortization of the regulatory assets, we do not expect it to have a material effect on our consolidated financial position, results of operations, or cash flows.

To ensure that collections by the SPE are neither more nor less than the amount necessary to pay interest, principal, and other related issuance costs, we are required to file for periodic adjustments, or reconciliations, to the annual amounts to be collected by the SPE. The PSC is required to approve these adjustments.

We retired at maturity $2,500,000 of 8.90 percent Series A Unsecured Medium-Term Notes (MTNs) on October 1, 1999.

On September 3, 1999, we retired $10,000,000 of our 7.875 percent Series B Unsecured MTNs due December 23, 2026. We retired an additional $5,000,000 of these MTNs on October 13, 1999.

As discussed in Note 2, "Contingencies," we recorded long-term debt of approximately $57,000,000 regarding the Kerr mitigation in June 1997. This amount represented the net present value of future costs to be paid over the life of the license. With the sale of the generating assets, payments after the sale date are no longer our responsibility. Therefore, we reduced debt on the sale date to approximately $24,300,000. On December 30, 1999, we paid approximately $14,100,000 of this amount. We included the remaining $10,200,000 in "Other" in the table above. The final payment for $10,200,000 occurred on January 3, 2000.

Scheduled debt repayments for the five years ending December 31, 2004, on the long-term debt outstanding at December 31, 1999, amount to: $43,000,000 in 2000; $89,000,000 in 2001; $4,000,000 in 2002; $19,000,000 in 2003; $5,000,000 in 2004; and $486,000,000 thereafter. However, as part of the Tier II rate filing discussed in Note 4, "Deregulation and Regulatory Matters," we indicated our intention to retire approximately $266,000,000 of long-term debt. We estimate that the expenses associated with these retirements will be approximately $20,000,000. As discussed above, we have already repurchased $15,000,000 of our 7.875 percent Series B Unsecured MTNs due December 23, 2026. In addition, we bought $5,000,000 of 7.25 percent Secured MTNs due January 19, 2024, and $7,000,000 of 8.68 percent Unsecured Series A MTNs due February 7, 2022, in January of 2000. We plan to retire additional long-term debt throughout 2000.

NOTE 11 - SHORT-TERM BORROWING:

We have short-term borrowing facilities with commercial banks that provide both committed and uncommitted lines of credit and the ability to sell commercial paper. Bank borrowings either bear interest at the lender's floating base rate and may be repaid at any time, or have fixed rates of interest and maturities. Commercial paper has fixed rates of interest and maturities.

At December 31, 1999, we had lines of credit consisting of $95,000,000 committed and $50,000,000 uncommitted. In addition, we share with Entech, Inc. (Entech, a wholly owned subsidiary of The Montana Power Company) a joint uncommitted credit line of $30,000,000, from which either company may borrow, but the sum of which borrowings cannot exceed the credit line. Facility fees or commitment fees on the committed lines of credit are not significant. We have the ability to issue up to $95,000,000 of commercial paper based on the total of unused committed lines of credit and revolving credit agreements.

At December 31, 1999 and 1998, we had no short-term obligations.

NOTE 12 - RETIREMENT PLANS:

We maintain trusteed, noncontributory retirement plans covering substantially all of our employees. Prior to 1998, our retirement benefits were based on salary, years of service, and social security integration levels. In 1998, we amended our retirement plans' benefit provisions. Our retirement benefits are now based on salary, age, and years of service.

Our plan assets consist primarily of domestic and foreign corporate stocks, domestic corporate bonds, and United States Government securities.

We also have an unfunded, nonqualified benefit plan for senior management executives and directors. In December 1998, we froze the benefits earned and curtailed the plan and accrued approximately $3,900,000 of expense in accordance with SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans."

As a result of the sale of our electric generating assets to PPL Montana, 454 participants related to electric generation operations were curtailed from the retirement plan and approximately $22,700,000 in assets were transferred from the retirement plan trust to the PPL retirement plan trust. Pursuant to the Agreement, approximately $3,200,000 of assets was transferred to the PPL trust in February 2000. In accordance with SFAS No. 88, we calculated a curtailment gain of approximately $4,100,000 and a settlement gain of approximately $7,800,000. Due to regulatory accounting treatment, the gains were recorded as regulatory liabilities or offsets to regulatory assets, resulting in no income statement impact.

We also provide certain health care and life insurance benefits for eligible retired employees. In 1994, we established a prefunding plan for postretirement benefits for utility employees retiring after January 1, 1993. The plan assets consist primarily of domestic and foreign corporate stocks, domestic corporate bonds, and United States Government securities. The PSC allows us to include in rates all utility Other Postretirement Benefits costs on the accrual basis provided by SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions."

We also have a voluntary retirement savings plan in conjunction with our retirement plans. We contribute a matching percentage comprised of shares from a leveraged Employee Stock Ownership Plan arrangement and shares purchased on the open market. For costs associated with these plans, see Note 7, "Common Stock."

The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 1999, and a statement of the funded status as of December 31 of both years:

	Pension Benefits		Other Benefits	
	1999	1998	1999	1998
	(Thousands of Dollars)			
Change in benefit obligation:				
Benefit obligation at January 1	$ 202,666	$ 211,407	$ 20,081	$ 20,142
Service cost on benefits earned	5,039	4,701	548	512
Interest cost on projected benefit obligation	14,394	13,635	1,429	1,376
Plan amendments	8,512	3,872	-	-
Actuarial (gain) loss	(22,720)	(17,200)	(397)	5,055
Curtailments	(5,712)	(3,923)	(3,092)	-
Settlements	(18,096)	-	-	-
Assets allocated from (to) related companies	-	-	-	(4,332)
Gross benefits paid	(10,606)	(9,826)	(1,862)	(2,672)
Benefit obligation at December 31	$ 173,477	$ 202,666	$ 16,707	$ 20,081
Change in plan assets:				
Fair value of plan assets at January 1	$ 222,484	$ 227,496	$ 7,898	$ 8,168
Actual return on plan assets	14,515	3,141	142	1,036
Employer contributions	-	-	2,531	1,842
Acquisitions/divestiture	(22,707)	-	-	-
Assets allocated from related companies	(545)	-	-	(884)
Gross benefits paid	(8,825)	(8,153)	(1,862)	(2,264)
Fair value of plan assets at December 31	$ 204,922	$ 222,484	$ 8,709	$ 7,898
Reconciliation of funded status:				
Funded status at January 1	$ 31,455	$ 19,818	$ (7,997)	$ (12,183)
Unrecognized net:				
Actuarial gain	(43,612)	(40,423)	(4,464)	(1,631)
Prior service cost	12,686	7,414	1,356	448
Transition (benefit) obligation	(202)	(242)	9,820	13,366
Net amount recognized at December 31	$ 317	$ (13,433)	$ (1,285)	$ -

The following table provides the amounts recognized in the statement of financial position as of December 31 of both years:

	Pension Benefits		Other Benefits	
	1999	1998	1999	1998
	(Thousands of Dollars)			
Prepaid benefit cost	$ 7,379	$ 3,963		
Accrued benefit cost	(7,062)	(17,396)	$ (1,285)	$ -
Net amount recognized at December 31	$ 317	$ (13,433)	$ (1,285)	$ -

The following tables provide the components of net periodic benefit cost for the pension and other post-retirement benefit plans, portions of which have been deferred or capitalized, for fiscal years 1999 and 1998:

	Pension Benefits		Other Benefits	
	1999	1998	1999	1998
	(Thousands of Dollars)			
Service cost on benefits earned	$ 5,038	$ 4,701	$ 548	$ 512
Interest cost on projected benefit obligation	14,394	13,634	1,429	1,376
Expected return on plan assets	(19,598)	(17,592)	(645)	(618)
Amortization of:				
Transition (benefit) obligation	(40)	196	955	955
Prior service cost	1,279	1,009	135	37
Actuarial gain	(1,208)	(743)	(100)	(230)
Net periodic benefit cost	(135)	1,205	2,322	2,032
Curtailment (gain) loss	(3,751)	3,307	(374)	-
Settlement gain	(7,844)	-	-	-
Net periodic benefit cost after curtailments	$ (11,730)	$ 4,512	$ 1,948	$ 2,032

In 1999, funding for pension costs exceeded SFAS No. 87, "Employers' Accounting for Pensions," pension expense by $1,630,000. In 1998, pension costs exceeded SFAS No. 87 pension expense by $1,780,000. The PSC allows recovery for the funding of pension costs through rates. Any differences between funding and expense are deferred for recognition in future periods as funding is reflected in rates. At December 31, 1999, the regulatory liability was $5,755,000.

The following assumptions were used in the determination of actuarial present values of the projected benefit obligations:

	Pension Benefits		Other Benefits	
	1999	1998	1999	1998
Weighted average assumptions as of December 31:				
Discount rate	7.75%	6.75%	7.75%	6.75%
Expected return on plan assets	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	4.40%	3.75%	4.40%	3.75%

Assumed health care costs trend rates have a significant effect on the amounts reported for the health care plans. A change of 1 percent in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(Thousands of Dollars)	
Effect on total of service and interest cost component of net periodic post-retirement health care benefit cost	$ 88	$ (82)
Effect on the health care component of the accumulated post-retirement benefit obligation	663	(623)

The assumed 2000 health care cost trend rates used to measure the expected cost of benefits covered by the plans is 7.00 percent. The trend rate decreases through 2004 to 5 percent.

NOTE 13 - SUBSEQUENT EVENT:

On March 28, 2000, we announced that we will offer for sale all of our energy businesses. These energy businesses consist of our regulated electric transmission and distribution operations; regulated natural gas transportation, distribution, and storage operations; coal operations; independent power operations; and oil and natural gas exploration, development, production, and processing operations, including operations involved with the trading and marketing of oil, natural gas, and natural gas liquids. At March 31, 2000, the total equity of the businesses that we will sell was approximately $1,100,000,000.

We expect the sale(s) to take six to twelve months to complete. Upon the completion of the sale(s) of our energy businesses, some of which are subject to shareholder approval, Touch America, Inc. will remain as the entity through which we will continue to conduct our telecommunications business. We intend to invest the funds received from the sale of our energy businesses into Touch America. We cannot predict the ultimate timing of the completion of these transactions, the amount of the proceeds to be received, the effect of the transactions on the rating of our outstanding securities, and other aspects of the transactions.

Sch. 19 **MONTANA PLANT IN SERVICE - ELECTRIC (EXCLUDES UNIT 4)**

	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Intangible Plant**					
3	301 Organization	$19,995		$19,995	$19,995	0.00%
4	302 Franchises and Consents	2,004		2,004	2,004	0.00%
5	303 Miscellaneous Intangible Plant	1,328,696		1,328,696	65,657,772	-97.98%
6	**Total Intangible Plant**	1,350,695	0	1,350,695	65,679,771	-97.94%
7						
8	**Production Plant**					
9						
10	**Steam Production**					
11	310 Land and Land Rights			0	2,550,541	-100.00%
12	311 Structures and Improvements			0	112,695,285	-100.00%
13	312 Boiler Plant Equipment			0	283,286,268	-100.00%
14	313 Engines, Engine Driven Generator					
15	314 Turbogenerator Units			0	76,915,744	-100.00%
16	315 Accessory Electric Equipment			0	33,289,577	-100.00%
17	316 Misc. Power Plant Equipment			0	11,190,337	-100.00%
18	**Total Steam Production Plant**	0	0	0	519,927,752	-100.00%
19						
20	**Nuclear Production**					
21	320 - 325 Not Applicable					
22	**Total Nuclear Production Plant**	0	0	0	0	0.00%
23						
24	**Hydraulic Production**					
25	330 Land and Land Rights	58,620		58,620	6,113,019	-99.04%
26	331 Structures and Improvements	119,451		119,451	40,918,973	-99.71%
27	332 Reservoirs, Dams and Waterways	8,895,177		8,895,177	89,861,771	-90.10%
28	333 Water Wheel, Turbine, Generators	124,613		124,613	44,318,727	-99.72%
29	334 Accessory Electric Equipment	99,660		99,660	12,579,724	-99.21%
30	335 Misc. Power Plant Equipment	90,351		90,351	3,262,471	-97.23%
31	336 Roads, Railroads and Bridges	35,337		35,337	3,243,463	-98.91%
32	**Total Hydraulic Production Plant**	9,423,208	0	9,423,208	200,298,148	-95.30%
33						
34	**Other Production**					
35	340 Land and Land Rights					
36	341 Structures and Improvements	26,049	15,967	10,082	10,083	0.00%
37	342 Reservoirs, Dams and Waterways	112,084	112,084	0	0	0.00%
38	343 Water Wheel, Turbine, Generators	0				
39	344 Accessory Electric Equipment	2,270,065	2,255,293	14,772	14,772	0.00%
40	345 Misc. Power Plant Equipment	119,307	101,896	17,411	17,411	0.00%
41	346 Roads, Railroads and Bridges	7,555	7,555	0	0	0.00%
42	**Total Other Production Plant**	2,535,060	2,492,794	42,266	42,266	0.00%
43	**Total Production Plant**	11,958,268	2,492,794	9,465,474	720,268,166	-98.69%
44						
45						
46						
47						
48						
49						
50						
51						
52						
53						

Sch. 19 cont.

MONTANA PLANT IN SERVICE - ELECTRIC (EXCLUDES UNIT 4)

	Account Number & Title	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Plant**					
3	350 Land and Land Rights	15,017,222	900	15,016,321	14,734,359	1.91%
4	352 Structures and Improvements	3,892,391		3,892,391	3,792,444	2.64%
5	353 Station Equipment	116,982,029		116,982,029	126,359,672	-7.42%
6	354 Towers and Fixtures	17,374,270	456	17,373,814	17,443,302	-0.40%
7	355 Poles and Fixtures	114,738,633	710,150	114,028,483	109,023,522	4.59%
8	356 Overhead Conductors & Devices	97,516,953	594,293	96,922,660	94,752,253	2.29%
9	357 Underground Conduit	98,764	102,286	(3,523)	(6,997)	49.66%
10	358 Undergrnd Conductors & Devices	1,179,110	554,036	625,074	257,501	142.75%
11	359 Roads and Trails	2,267,874	44,906	2,222,968	2,175,646	2.18%
12	**Total Transmission Plant**	369,067,245	2,007,027	367,060,218	368,531,702	-0.40%
13						
14	**Distribution Plant**					
15	360 Land and Land Rights	3,418,751	601	3,418,150	3,264,391	4.71%
16	361 Structures and Improvements	3,671,963	141,867	3,530,097	3,455,183	2.17%
17	362 Station Equipment	85,222,486	1,921,136	83,301,350	81,313,612	2.44%
18	363 Storage Battery Equipment	0				
19	364 Poles, Towers, and Fixtures	101,801,530	223,656	101,577,874	96,940,160	4.78%
20	365 Overhead Conductors & Devices	63,878,299	325,922	63,552,377	60,878,559	4.39%
21	366 Underground Conduit	17,792,878	92,647	17,700,231	16,780,706	5.48%
22	367 Undergrnd Conductors & Devices	62,052,551	2,478,781	59,573,770	55,071,093	8.18%
23	368 Line Transformers	115,546,747	714,984	114,831,762	111,256,117	3.21%
24	369 Services	57,725,236	212,052	57,513,184	54,642,912	5.25%
25	370 Meters	26,679,997	67,143	26,612,854	26,558,028	0.21%
26	371 Installations on Cust. Premises	0				
27	372 Leased Property on Cust. Premises					
28	373 Street Lighting and Signal Systems	35,740,905	19,872	35,721,033	34,491,661	3.56%
29	**Total Distribution Plant**	573,531,343	6,198,661	567,332,681	544,652,422	4.16%
30						
31	**General Plant**					
32	389 Land and Land Rights	326,186		326,186	304,480	7.13%
33	390 Structures and Improvements	7,098,954	$84,207	7,014,747	6,899,781	1.67%
34	391 Office Furniture and Equipment	1,925,052		1,925,052	1,007,287	91.11%
35	392 Transportation Equipment	23,483,396	93,890	23,389,506	23,094,053	1.28%
36	393 Stores Equipment	436,080		436,080	413,177	5.54%
37	394 Tools, Shop & Garage Equipment	4,146,145	41,751	4,104,394	4,129,885	-0.62%
38	395 Laboratory Equipment	4,424,221	7,824	4,416,397	4,510,396	-2.08%
39	396 Power Operated Equipment	2,242,579		2,242,579	2,241,963	0.03%
40	397 Communication Equipment	18,273,117	76,170	18,196,947	17,632,193	3.20%
41	398 Miscellaneous Equipment	134,176	88,417	45,759	63,930	-28.42%
42	399 Other Tangible Equipment	824,515		824,515	815,467	1.11%
43	**Total General Plant**	63,314,422	392,259	62,922,163	61,112,612	2.96%
44	**Total Plant in Service**	1,019,221,973	11,090,742	1,008,131,231	1,760,244,673	-42.73%
45						
46	4101 El Plant Allocated from Common	24,447,691		24,447,691	26,305,400	-7.06%
47	105 El Plant Held for Future Use	0		0	1,727,225	-100.00%
48	107 El Construction Work in Progress	3,017,434		3,017,434	37,713,878	-92.00%
49	114.2 El Plant Acquisition Adjustment	3,106,285		3,106,285	3,106,285	0.00%
50		0				
51	**TOTAL ELECTRIC PLANT**	$1,049,793,383	$11,090,742	$1,038,702,641	$1,829,097,461	-43.21%
52						
53						

Sch. 20 **MONTANA DEPRECIATION SUMMARY - ELECTRIC (EXCLUDES UNIT 4)**

	Functional Plant Class	Montana Plant Cost	This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**						
2							
3	Steam Production	$0	($1,226,080)		($1,226,080)	$235,699,409	2.79%
4							
5	Nuclear Production						
6							
7	Hydraulic Production	9,423,208	4,799,019		4,799,019	59,989,360	1.43%
8							
9	Other Production	42,266	0	1,221,339	0	0	0.00%
10							
11	Transmission	367,060,218	102,459,320	1,050,561	101,408,759	97,876,180	2.90%
12							
13	Distribution	567,332,681	196,738,570	2,187,620	194,550,950	175,306,822	3.85%
14							
15	General and Intangible	64,272,858	27,208,351	205,145	27,003,206	29,640,512	5.06%
16							
17	Common	24,447,691	4,794,067		4,794,067	5,883,960	4.25%
18							
19	**TOTAL DEPRECIATION**	$1,032,578,922	$334,773,247	$4,664,665	$331,329,921	$604,396,243	3.05%

Sch. 21 MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - ELECTRIC (EXCLUDES UNIT4)

Account Number & Title		This Year Cons. Utility	Yellowstone National Park	This Year Montana	Last Year Montana	%Change
151	Fuel Stock	$29,920		$29,920	$942,237	-96.82%
152	Fuel Stock Expenses Undistributed					
153	Residuals	0		0		
154	Plant Materials & Operating Supplies					
	Assigned and Allocated to;					
	Operation & Maintenance					
	Construction					
	Production Plant	(364,271)		(364,271)	8,920,162	-104.08%
	Transmission Plant	2,373,561		2,373,561	1,707,815	38.98%
	Distribution Plant	3,688,520		3,688,520	2,538,945	45.28%
155	Merchandise					
156	Other Materials & Supplies					
157	Nuclear Materials Held for Sale					
163	Stores Expense Undistributed	0		0	526,583	-100.00%
TOTAL MATERIALS & SUPPLIES		$5,727,730	$0	$5,727,730	$14,635,742	-60.86%

Sch. 22 **MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - ELECTRIC**

	% Capital Structure	% Cost Rate	Weighted Cost
Commission Accepted - Most Recent 1/			
Docket Number: 95.9.128			
Order Number : 5865d			
Common Equity	46.35%	11.00%	5.10%
Preferred Stock	7.91%	7.13%	0.56%
Long Term Debt	45.74%	7.44%	3.40%
Other			
TOTAL	100.00%		9.06%
Actual at Year End			
Common Equity	44.25%	11.00%	4.87%
Preferred Stock	4.99%	6.40%	0.32%
QUIPS Preferred 2/	5.62%	8.54%	0.48%
Long Term Debt 3/	45.14%	7.16%	3.23%
Other			
TOTAL	100.00%		8.90%

1/ Docket 95.9.128, Order 5865d only specified the return on equity component of the rate of return. The capital structure and the rates for long-term debt and preferred as filed in Rebuttal Testimony of P. J. Cole were not contested by the intervenors in the settlement stipulation. As such, the Company assumes the capital structure to be accepted by the Commission with the ordered change to return on equity.

2/ The cost of the QUIPS securities is treated as tax deductible for income tax purposes. See footnote on Schedule 25.

3/ The cost rate cannot be tied directly to Schedule 24, which is presented on a consolidated basis.

Sch. 23	STATEMENT OF CASH FLOWS (INCLUDES UNIT 4) - 1/			
	Description	This year	Last Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$150,346,186	$165,620,479	-9.22%
4	Depreciation	65,379,227	63,647,638	2.72%
5	Amortization	94,964	94,914	0.05%
6	Deferred Income Taxes - Net	(229,860,897)	(968,073)	-23644.17%
7	Investment Tax Credit Adjustments - Net	(20,489,428)	(1,362,593)	-1403.71%
8	Change in Operating Receivables - Net	(84,975,028)	(119,523,739)	28.91%
9	Change in Materials, Supplies & Inventories - Net	9,976,648	(1,018,940)	1079.12%
10	Change in Operating Payables & Accrued Liabilities - Net	46,124,030	150,306,893	-69.31%
11	Allowance for Funds Used During Construction (AFUDC)	(1,306,462)	(1,687,683)	22.59%
12	Change in Other Assets & Liabilities - Net	0	28,215,585	-100.00%
13	Other Operating Activities:			
14	Undistributed Earnings from Subsidiary Companies	(83,060,370)	(108,043,440)	23.12%
15	Amortization of Loss on Long-Term Sale of Power	0	0	
16	Other (net)	81,075,012	1,072,800	7457.33%
17	Change in Regulatory Assets	36,714,914	57,723,568	-36.40%
18	Change in Regulatory Liabilities	14,449,446	(1,774,132)	914.45%
19	**Net Cash Provided by/(Used in) Operating Activities**	($15,531,758)	$232,303,277	-106.69%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	($61,706,077)	($77,705,271)	20.59%
22	(net of AFUDC & Capital Lease Related Acquisitions)			
23	Sale of Generation Assets	758,191,797	0	
24	Contributions In and Advances to Affiliates	0	(20,001,000)	100.00%
25	Other Investing Activities:			
26	Miscellaneous Special Funds	(473,460,039)	249,218	-190078.27%
27	**Net Cash Provided by/(Used in) Investing Activities**	$223,025,681	($97,457,053)	328.85%
28	**Cash Flows from Financing Activities:**			
29	Proceeds from Issuance of:			
30	Long-Term Debt	$23,195,420	$65,356,067	-64.51%
31	Common Stock	606,635	7,360,080	-91.76%
32	Other: Manditorily Redeem. Pref. Securities of Sub. Trust			
33	Dividends from Subsidiaries	138,900,000	6,500,000	2036.92%
34	Net Increase in Short-Term Debt	0	(69,100,000)	100.00%
35	Other: Return of Subsidiary Capital			
36	Payment for Retirement of:			
37	Long-Term Debt	(143,184,896)	(44,971,857)	-218.39%
38	Preferred Stock	0	0	
39	Net Decrease in Short-Term Debt			
40	Dividends on Preferred Stock	(3,690,034)	(3,690,034)	0.00%
41	Dividends on Common Stock	(88,155,092)	(88,008,355)	-0.17%
42	Other Financing Activities (explained on attached page)	(144,871,974)		
43	**Net Cash Provided by (Used in) Financing Activities**	($217,199,941)	($126,554,099)	-71.63%
44				
45	**Net Increase/(Decrease) in Cash and Cash Equivalents**	($9,706,018)	$8,292,125	-217.05%
46	**Cash and Cash Equivalents at Beginning of Year**	$2,640,563	($5,651,562)	146.72%
47	**Cash and Cash Equivalents at End of Year**	($7,065,455)	$2,640,563	-367.57%
48				
49	1/ The cash balances on the 1999 and 1998 balance sheets includes CMP, whereas the cash flows			
50	statement does not.			
51				
52	2/ The amount listed on line 42 is the amount paid to reacquire Company Stock.			
53				
54				

Sch. 24

LONG TERM DEBT 1/

Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
First Mortgage Bonds								
7.50% Series, Due 2001	04/21/71	04/01/01	$25,000,000	$24,695,993	$24,990,885	7.500%	$1,885,134	7.54%
8.25% Series, Due 2007	12/05/91	02/01/07	55,000,000	54,550,100	54,789,882	8.260%	4,745,944	8.66%
8.95% Series, Due 2022	12/05/91	02/01/22	50,000,000	49,536,500	49,661,978	8.957%	4,571,783	9.21%
7.00% Series, Due 2005	03/01/93	03/01/05	50,000,000	49,375,000	49,730,903	7.075%	3,682,778	7.41%
Total First Mortgage Bonds			$180,000,000	$178,157,593	$179,173,648		$14,885,639	8.31%
Pollution Control Bonds								
6-1/8% Series, Due 2023	06/30/93	05/01/23	$90,205,000	$88,199,743	$88,636,643	5.841%	$5,639,099	6.36%
5.90% Series, Due 2023	12/30/93	12/01/23	80,000,000	79,040,800	79,229,774	6.428%	4,894,714	6.18%
Total Pollution Control Bonds			$170,205,000	$167,240,543	$167,866,417		$10,533,813	6.28%
Other Long Term Debt								
Quarterly Income Preferred Securities,								
8.45%, Series A (QUIPS) 2/	11/96	11/01	$ 65,000,000	$ 65,000,000	$ 65,000,000		$ 5,553,305	8.54%
Medium Term Notes-Unsecured Series A	Various	Various	7,000,000	7,000,000	7,000,000		609,814	8.71%
Medium Term Notes-Secured Series	Various	Various	68,000,000	68,000,000	68,000,000		5,165,080	7.60%
Medium Term Notes-Unsecured Series B	Various	Various	100,000,000	99,805,000	99,818,558		6,975,118	6.99%
Total Other Long Term Debt			$240,000,000	$239,805,000	$239,818,558		$18,303,317	7.63%
TOTAL LONG TERM DEBT			$590,205,000	$585,203,136	$586,858,623		$43,722,769	7.45%

1/ Total Long-Term Debt does not include ESOP debt of $16,197,000, as ESOP debt is not used for rate making purposes.
Total Long-Term Debt does not include amounts due within 1 year of $43,412,179.

2/ The Company believes and intends to take the position that the securities associated with the QUIPS issue will constitute indebtedness for United States federal income tax purposes. As such, the cost of QUIPS are deemed to be tax deductible. The Company will have the right to redeem securities (i) on of after November 6, 2001 or (ii) upon occurance and continuation of a Tax Event or an Investment Company Event, as defined in the Prospectus dated November 1, 1996.

Sch. 25

PREFERRED STOCK

Series	Issue Date	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embedded Cost %
$6.00 Series Cumulative	1929-1932	159,589	$100	$110.000	$15,958,900	6.00%	$15,958,900	$957,534	6.00%
$4.20 Series Cumulative	May 1954	60,000	$100	$103.000	6,024,600	4.18%	6,024,600	252,000	4.18%
$6.875 Series Cumulative 1/	Nov 1993	360,800	$100	$103.438	35,670,412	6.88%	35,670,412	2,480,500	6.95%
TOTAL PREFERRED STOCK		580,389			$57,653,912	6.40%	$57,653,912	$3,690,034	6.40%

1/ Not redeemable prior to November 1, 2003, at which point call price will decrease by .344 per year to equal 100.00 at November 1, 2013.

COMMON STOCK

	Avg. Number of Shares Outstanding 1/	Book Value Per Share 2/	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
January	110,128,374	$10.21				$28.44	$24.94	
February	110,150,838	10.28				30.44	24.56	
March	110,158,724	10.20	$0.30	$0.20		41.00	29.19	
April	110,159,660	10.28				42.63	35.78	
May	110,196,460	10.35				41.25	31.56	
June	110,198,030	10.24	$0.22	$0.20		37.34	33.19	
July	110,199,430	10.08				36.31	32.34	
August	110,201,392	10.19				35.00	27.50	
September	110,201,392	10.10	$0.26	$0.20		34.31	28.50	
October	110,201,392	10.23				34.13	26.81	
November	110,203,073	10.34				31.38	27.19	
December	105,536,873	9.56	$0.56	$0.20		37.38	30.69	
TOTAL COMMON	109,794,637	$9.56	$1.34	$0.80	40.30%	$42.63	24.56	31.8

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for 1999

2/ All Book Value Per Share amounts are based on actual shares and include unallocated stock held by Trustee for the Deferred Savings and Employee Ownership Plans.

3/ All market prices are adjusted to reflect the stock split which was effective 8/9/99.

Sch. 27	MONTANA EARNED RATE OF RETURN - ELECTRIC			
	Description	Last Year	This Year	% Change
1	**Rate Base**			
2	101 Plant in Service	$1,768,756,449	$1,748,181,224	-1.16%
3	108 Accumulated Depreciation	(583,188,741)	(607,582,266)	-4.18%
4				
5	**Net Plant in Service**	$1,185,567,708	$1,140,598,958	-3.79%
6	Additions:			
7	154, 15 Materials & Supplies	$13,681,727	$12,028,433	-12.08%
8	165 Prepayments	0	0	0.00%
9	Other Additions 1/	196,718,767	182,971,835	-6.99%
10				
11	**Total Additions**	$210,400,494	$195,000,268	-7.32%
12	Deductions:			
13	190 Accumulated Deferred Income Taxes 1/	$232,067,195	$218,662,186	-5.78%
14	252 Customer Advances for Construction	13,610,664	15,072,721	10.74%
15	255 Accumulated Def. Investment Tax Credits	0	0	0.00%
16	Other Deductions	14,515,019	60,153,616	314.42%
17				
18	**Total Deductions**	$260,192,878	$293,888,523	12.95%
19	**Total Rate Base**	$1,135,775,324	$1,041,710,703	-8.28%
20	**Net Earnings**	$96,818,201	$79,944,108	-17.43%
21	**Rate of Return on Average Rate Base**	8.524%	7.674%	-9.97%
22	**Rate of Return on Average Equity 2/**	8.802%	7.883%	-10.44%
23				
24	**Major Normalizing and**			
25	**Commission Ratemaking Adjustments**			
26				
27	Rate Schedule Revenues	$1,254,221	$4,619,636	268.33%
27	Revenue Choice Customers	0	32,537,920	-
28	Off-System Sales Market	8,020,866	(33,245,970)	-514.49%
29	Sales-Purchased Power	(314,040)	(1,141,133)	-263.37%
30	Hydro Generation	(3,840,564)	(4,094,620)	-6.62%
31	Thermal Generation	309,851	(2,583,750)	-933.87%
32	Interest Excess Proceeds Generation Sale	0	346,640	-
33				
34	Non-Allowables:			
35	Advertising	1,667,568	769,816	-53.84%
36	Benefit Restoration Plan	2,408,398	350,970	-85.43%
37	Dues, Contributions, Other	78,388	109,552	39.76%
38	Corporate Overhead	13,292	318,156	2293.59%
39	Other Settlement Items	2,500,000	0	-100.00%
40				
41	Associated Income Taxes	(4,765,092)	792,785	116.64%
42	**Total Adjustments**	$7,332,888	($1,219,998)	-116.64%
43	**Revised Net Earnings**	$104,151,089	$78,724,110	-24.41%
44	**Adjusted Rate of Return on Average Rate Base**	9.170%	7.557%	-17.59%
45	**Adjusted Rate of Return on Average Equity 2/,3/**	10.300%	7.618%	-26.04%
46				
47	1/ Includes adjustments related to FAS 109.			
48				
49	2/ The 1999 ROE calculation utilizes the common equity component on Sch. 22 of this Report,			
50	applied to rate base for the denominator of the equations. The 1998 common equity component			
51	applied to rate base was 43.10%.			
52				

Sch. 27 cont. **MONTANA EARNED RATE OF RETURN - ELECTRIC**

	Description	Last Year	This Year	% Change
1				
2	**Detail - Other Additions**			
3	FAS 109 Regulatory Asset	$112,025,239	$103,089,382	-7.98%
4	Conservation Expenditures	33,109,339	30,924,544	-6.60%
5	Cost of Refinancing Debt	7,595,972	7,071,181	-6.91%
6	Colstrip Unit 3 Carrying Charge	41,240,546	39,409,802	-4.44%
7	Corette PS&I	373,821	334,471	-10.53%
8	Fuel	1,043,755	800,770	-23.28%
8	Division Centralization	93,953	93,953	0.00%
9	Qualifying Facilities Buyout	0	11,590	-
10	1995 & 1996 Severance Costs	813,235	813,235	0.00%
11	1994 Severance Costs	422,907	422,907	0.00%
12	**Total Other Additions**	$196,718,767	$182,971,835	-6.99%
13				
14	**Detail - Other Deductions**			
15	Personal Injury and Property Damage	$1,729,059	$1,993,422	15.29%
16	Deferred Taxes - CIAC	0	0	-
17	Unamortized Gain on Reacquired Debt	91,492	36,239	-60.39%
18	Gross Cash Requirements	9,906,912	11,160,965	12.66%
19	Mystic Lake Adjustment	501,903	419,336	-16.45%
18	Kerr Mitigation	0	0	-
19	Storm Damage Reserve	(77,054)	315,527	509.49%
20	WAPA/BPA Billing Adjustment	2,198,666	2,198,666	0.00%
20	Materials & Supplies Non-Consumable Par	210,041	321,086	52.87%
20	USBC Expenses	0	560,468	-
21	Net Kerr Mitigation	0	43,147,907	-
22				
23	**Total Other Deductions**	$14,561,019	$60,153,616	313.11%
24				

25 3/ In accordance with accounting order no. 5865e received as a result of Docket No. D95.9.128,
26 $6,160,676 of 1997 ITC was flowed through to income in nonoperating accounts and therefore
27 was not included in this return calculation.

Sch. 28	MONTANA COMPOSITE STATISTICS - ELECTRIC (EXCLUDES UNIT 4 & YNP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	$1,032,578,922
5	105	Plant Held for Future Use	0
6	107	Construction Work in Progress	3,017,434
7	114	Plant Acquisition Adjustments	3,106,285
8	151-163	Materials & Supplies	5,727,730
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	331,329,921
11	252	Contributions in Aid of Construction	14,291,276
12	**NET BOOK COSTS**		$698,809,174
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	$485,926,640
17			
18	**Total Operating Revenues**		$485,926,640
19			
20	401-402	Other Operating Expenses	$271,852,615
21	403-407	Depreciation & Amortization Expenses	53,137,302
22	408.1	Taxes Other than Income Taxes	50,857,524
23	409-411	Federal & State Income Taxes	30,135,091
24			
25	**Total Operating Expenses**		$405,982,532
26	**Net Operating Income**		$79,944,108
27			
28	415-421.1	Other Income	$3,803,303
29	421.2-426.5	Other Deductions	(814,119)
30	**NET INCOME BEFORE INTEREST EXPENSE**		$82,933,292
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	232,328
34		Commercial & Industrial	48,876
35		Other	3,599
36			
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		284,803
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Kwh)	7,862
41		Average Annual Residential Cost per (Kwh)	$0.071
42		Average Residential Monthly Bill	$46.59
43			
44		Plant in Service (Gross) per Customer	$3,626
45			
46			
47			
48			
49			
50			
51			
52			
53			

City	Population 7/1/98 Estimates	Residential	Commercial	Industrial & Other	Total
Absarokee		444	107	11	562
Alberton	407	432	89	32	553
Amsterdam		1	1		2
Anaconda	9999	4142	664	85	4891
Augusta		235	74	9	318
Avon		89	47	7	143
Barber		50	8	1	59
Basin		156	59	9	224
Bearcreek-Washoe	42	69	14	3	86
Belfry		191	51	38	280
Belgrade	5018	3887	726	88	4701
Belt	578	613	185	18	816
Big Sandy	698	373	125	16	514
Big Sky		1499	301	3	1803
Big Timber	1689	1144	339	39	1522
Bigfork		661	113		774
Billings	91750	39304	6682	810	46796
Boulder	1654	709	198	44	951
Box Elder		122	60	10	192
Bozeman	29936	16889	3024	224	20137
Brady		1	2	2	5
Bridger	824	392	117	37	546
Broadview	187	223	149	10	382
Butte	33994	14390	1984	418	16792
Carter		120	51	14	185
Cascade	725	963	202	34	1199
Chester	959	520	251	38	809
Chinook	1590	847	268	52	1167
Choteau	1802	969	316	46	1331
Clancy		1308	200	6	1514
Clinton		93	26	6	125
Coffee Creek		33	16		49
Colstrip		933	149	59	1141
Columbus	2072	898	250	36	1184
Conrad	2903	1239	326	136	1701
Corbin-Jefferson		190	31	3	224
Corvallis		591	127	85	803
Darby	942	667	180	39	886
Deer Lodge	3700	1997	427	154	2578
Denton	361	161	33	5	199
Dillon	4267	1851	461	118	2430
Dodson	127	122	46	18	186
Drummond	278	568	244	106	918
Dutton	392	256	94	34	384
East Helena	1750	2152	273	34	2459

Edgar		269	73	14	356
Elliston		185	53	12	250
Ennis-Jeffers	1017	1622	468	83	2173
Fairfield	681	405	128	53	586
Florence		313	97	25	435
Floweree		106	52	7	165
Fort Benton	1613	805	290	53	1148
Fromberg	442	299	60	23	382
Gallatin Gateway		897	214	20	1131
Gardiner		723	249	19	991
Garrison		104	44	12	160
Geraldine	286	275	105	9	389
Geyser		62	15	4	81
Gildford		95	62	12	169
Glasgow	3590	1935	600	105	2640
Great Falls	56395	27320	4103	453	31876
Greycliff		53	23	14	90
Hamilton	4463	4450	1013	200	5663
Hardin	3316	1395	405	60	1860
Harlem	982	858	257	62	1177
Harlowtown	1097	642	173	26	841
Harrison		156	47	45	248
Haugan-Deborgia		190	60	5	255
Havre	10015	4944	909	214	6067
Helena	28306	19037	3561	464	23062
Hingham	174	111	57	8	176
Hinsdale		141	42	6	189
Hobson	230	142	30		172
Iverness		49	23	6	78
Jardine			5		5
Joilet	637	352	77	23	452
Joplin		107	52	8	167
Judith Gap	144	87	22	3	112
Kremlin		75	37	4	116
Laruin-Alder		181	53	20	254
Laurel	6027	2839	248	27	3114
Lavina	177	182	82	28	292
Lennep-Ringling		58	38	6	102
Lewistown	6159	3237	720	98	4055
Lincoln		958	205	7	1170
Livingston	7348	4101	857	128	5086
Logan		3	6	4	13
Lohman		18	11	21	50
Lolo		1146	153	37	1336
Loma		76	37	11	124
Malta	2209	1370	381	84	1835
Mammoth		165	67	2	234
Manhattan	1423	1464	274	161	1899
Martinsdale		141	34	2	177

Marysville		200	49	14	263
Melstone	189	121	90	81	292
Missoula	52239	27800	4715	783	33298
Moccasin		42	18	3	63
Monarch		324	28	9	361
Moore	212	97	17	4	118
Musselshell		53	12	2	67
Nashua	373	214	56	10	280
Neihart	50	182	25	1	208
Norris		54	27	6	87
Paradise		147	40	22	209
Park City		387	34	6	427
Philipsburg	971	1511	215	36	1762
Plains	1217	1238	295	129	1662
Pony		117	21	4	142
Power		79	42	7	128
Radersburg		107	51	45	203
Raynesford		68	25	2	95
Red Lodge	2238	1666	339	26	2031
Reedpoint		127	46	9	182
Roberts		141	17		158
Roundup	2012	1125	356	87	1568
Rudyard		163	66	7	236
Ryegate		141	61	22	224
Saco	235	162	70	16	248
Saltese		35	20	4	59
Sand Coulee		260	58	7	325
Saphire Village		57	2		59
Shawmut		42	16		58
Sheridan	733	760	176	45	981
Springdale		34	15	8	57
Square Butte		20	5		25
St. Regis		374	124	20	518
Stanford	539	283	84	16	383
Stevensville	2046	1559	434	115	2108
Stockett		167	38	2	207
Superior	980	754	243	24	1021
Thompson Falls	1556	917	254	57	1228
Three Forks	1528	1123	367	110	1600
Total Customers (MT)		229288	44213	7364	280865
Townsend	2092	1008	237	45	1290
Trident		2			2
Twin Bridges	429	311	136	40	487
Twodot		30	9	3	42
Ulm		365	97	11	473
Valier	544	112	51	48	211
Vaughn		224	31	7	262
Victor		684	212	39	935
Virginia City	160	140	75	5	220

Wagner		46	17	2	65
White Sulphur	968	751	294	59	1104
Whitehall	1399	925	204	101	1230
Willow Creek		131	47	33	211
Windham		26	10	1	37
Winston		80	24	8	112
Wolf Creek	2854	474	122	13	609
Yellowstone Park			172	166	338
Zurich		104	51	35	190

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MONTANA EMPLOYEE COUNTS

Department	Year Beginning 1/	Year End 1/	Average
Utility Operations			
Executive			
Financial, Risk Mgmt. & Information Services			
Administrative & Regulatory Affairs			
Utility Services & Division Administration	795	703	749
Corporate Administration	211	170	191
Business Development & Regulatory Affairs	23	18	21
Transmission	152	199	175
Generation	486	1	244
Total Utility	1,667	1,091	1,379
Other Corporate			
Office of the Corporation			
Total Other Corporate	0		0
TOTAL EMPLOYEES	1,667	1,091	1,379

1/ Part time employees have been converted to full time equivalents.

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MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) - 1999

Project Description	Total Company	Total Montana
Electric Operations		
Shiloh Road Substation	$1,500,000	$1,500,000
Rainbow - Canyon Ferry Taps 100KV "A" &"B" Tower Lines	2,009,820	2,009,820
All Other Projects < $1 Million Each	35,085,137	35,085,137
Total Electric Utility Construction Budget	$38,594,957	$38,594,957
Natural Gas Operations		
Upgrade Main Line # 3 Compressor	$3,200,000	$3,200,000
Dry Creek Storage Compression	1,600,000	1,600,000
All Other Projects < $1 Million Each	10,383,500	10,383,500
Total Natural Gas Utility Construction Budget	$15,183,500	$15,183,500
Common		
Software/Connect MPC Enterprise System	14,651,847	14,651,847
All Other Projects < $1 Million Each	5,531,948	5,531,948
Total Common Utility Construction Budget	$20,183,795	$20,183,795
Colstrip Unit 4		
Total Colstrip Unit 4 Construction Budget	$0	$0
TOTAL CONSTRUCTION BUDGET	$73,962,252	$73,962,252

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TOTAL SYSTEM & MONTANA PEAK AND ENERGY

		System Peak and Energy				
		Peak Day	Peak Hour	Peak Day Volume Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	January	25	800	1,328	1,030,009	497,312
2	February	2	2000	1,302	947,671	504,302
3	March	1	2000	1,201	1,007,647	602,343
4	April	1	2100	1,127	1,107,771	671,079
5	May	28	1500	1,177	927,096	533,103
6	June	21	1500	1,235	740,308	372,055
7	July	28	1500	1,412	968,344	488,730
8	August	3	1600	1,338	978,788	532,820
9	September	27	2100	1,158	896,973	542,157
10	October	18	2000	1,167	932,732	502,495
11	November	22	1900	1,284	1,064,625	642,471
12	December	13	1900	1,376	893,489	433,557
13	**TOTALS**				11,495,453	6,322,424
14		Montana Peak and Energy				
15		Peak	Peak	Peak Day Volume	Total Monthly Volumes	Non-Requirements
16		Day	Hour	Megawatts	Energy (Mwh)	Sales For Resale (Mwh)
17	January					
18	February					
19	March					
20	April					
21	May					
22	June					
23	July				NOT AVAILABLE	
24	August					
25	September					
26	October					
27	November					
28	December					
29	**TOTALS**				0	0
30						
31						
32						
33						
34						
35						
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Sch. 33 TOTAL SYSTEM SOURCES & DISPOSITION OF ENERGY

	Sources	Megawatthours	Dispositions	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	6,252,761		
3	Nuclear		**Sales to Ultimate Consumer**	7,401,078
4	Hydro - Conventional	3,691,521	(Include Interdepartmental)	
5	Hydro - Pumped Storage			
6	Other	680	Sales for Resale	
7	(Less) Energy for Pumping		Requirement Sales	591,690
8	**Net Generation**	9,944,962	Non-Requirement Sales	5,730,734
9	**Purchases**	2,760,212	**Sales for Resale**	6,322,424
10	Power Exchanges		Energy Furnished w/o Charge	
11	Received	1,481,497		
12	Delivered	1,516,293		
13	**Net Power Exchanges**	(34,796)	**Energy Furnished**	0
14	Transmission Wheeling for Others		Energy Used Within Utility	
15	Received	3,301,064	Electric Department	
16	Delivered	3,083,982	(Less) Station Use	
17	**Net Transmission Wheeling**	217,082	**Net Energy Used Within Util.**	0
18	**Transmission by Others Losse**	0	**Energy Losses**	(836,042)
19	**TOTAL SOURCES**	12,887,460	**TOTAL DISPOSITIONS**	12,887,460

Sch. 34	SOURCES OF ELECTRIC SUPPLY				
	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	J.E. Corette	Billings, MT	153.0	1,015,337.0
2	Thermal	Colstrip 1&2	Colstrip, MT	313.0	2,102,210.0
3	Thermal	Colstrip 3&4	Colstrip, MT	457.0	3,135,213.6
4	Subtotal			923.0	6,252,760.6
5					
6	Hydro	Black Eagle	Great Falls, MT	20.0	130,325.0
7	Hydro	Cochrane	Great Falls, MT	55.0	317,058.0
8	Hydro	Hauser	Helena, MT	17.0	127,113.0
9	Hydro	Holter	Helena, MT	50.0	333,995.0
10	Hydro	Kerr	Polson, MT	193.0	1,112,198.0
11	Hydro	Morony	Great Falls, MT	49.0	326,311.0
12	Hydro	Mystic Lake	Columbus, MT	11.0	48,613.0
13	Hydro	Rainbow	Great Falls, MT	37.0	254,884.0
14	Hydro	Ryan	Great Falls, MT	60.0	446,003.0
15	Hydro	Thompson Falls	Thompson Falls, MT	90.0	523,359.0
16	Hydro	Madison	Ennis, MT	9.0	55,848.0
17	Hydro	Milltown	Missoula, MT	3.0	15,815.0
18	Subtotal			594.0	3,691,522.0
19	Internal Combustion	Lake	Yellowstone Nat'l Park	0.0	144.8
20	Internal Combustion	Old Faithful	Yellowstone Nat'l Park	0.0	194.5
21	Internal Combustion	Tower Falls	Yellowstone Nat'l Park	0.0	337.0
22	Internal Combustion	Grant Village	Yellowstone Nat'l Park	0.0	3.4
23	Subtotal			0.0	679.7
24	Purchases	Small Power Producers	Colstrip Energy, Ltd.	0.0	309,349.0
25	Purchases	Small Power Producers	Billings Generation, Inc.	0.0	445,827.0
26	Purchases	Small Power Producers	State of Montana - DNRC	0.0	55,367.0
27	Purchases	Small Power Producers	Others	0.0	15,509.0
28					
29	Purchases	Nonassociated Utilities	Idaho Power - Capacity	0.0	27,146.0
30	Purchases	Nonassociated Utilities	Idaho Power - Secondary	0.0	25,281.0
31	Purchases	Nonassociated Utilities	Pacificorp	0.0	12,895.0
32	Purchases	Nonassociated Utilities	Portland General Electric	0.0	19,173.0
33	Purchases	Nonassociated Utilities	Powerex	0.0	14,982.0
34	Purchases	Nonassociated Utilities	PPL Montana	0.0	207,510.0
35	Purchases	Nonassociated Utilities	Washington Water Power - Secondary	0.0	908,004.0
36	Purchases	Nonassociated Utilities	Others	0.0	16,458.0
37					
38	Purchases	Other Public Authorities	Bonneville Power Administration - Secon	0.0	36,008.0
39	Purchases	Other Public Authorities	Public Service of Colorado - Secondary	0.0	39,270.0
40	Purchases	Other Public Authorities	Western Area Power Admin.	0.0	132,480.0
41	Purchases	Other Public Authorities	Others	0.0	7,563.0
42					
43	Purchases	Cooperatives	Basin Electric Cooperative	0.0	334,652.0
44	Purchases	Cooperatives	Rocky Mountain Generation Cooperative	0.0	13,117.0
45					
46	Purchases	Municipalities	Los Angeles Dept of Water & Power	0.0	9,177.0
47	Purchases	Municipalities	Seattle City Light	0.0	5,379.0
48	Purchases	Municipalities	Tacoma City Light	0.0	1,206.0
49					
50	Purchases	Marketing Agencies	Aquila Power	0.0	22,916.0
51	Purchases	Marketing Agencies	Avista Energy	0.0	53,874.0
52	Purchases	Marketing Agencies	Cargill Alliant	0.0	37,149.0
53	Purchases	Marketing Agencies	Others	0.0	12,196.0
54	Subtotal			0.0	2,762,488.0

Sch. 34	SOURCES OF ELECTRIC SUPPLY (Cont.)		
		OUTAGES	
	Start Date	Description	Duration(Hrs)
1		**J.E. CORETTE**	
2	01/17/99	Loss Excitation	1.63
3	01/20/99	Clean Boiler	131.12
4	02/03/98	Repair PO4 Line	21.65
5	02/15/98	Tube Leak	46.08
6	03/16/98	Loss Excitation	2.43
7	04/01/99	Loss Excitation	1.42
8	05/03/99	Valve at steam Drum	8.68
9	05/14/99	Annual Overhaul	869.78
10	06/24/99	Tube Leak	30.50
11	08/31/99	Leak	24.87
12	09/02/99	Loss Excitation	3.77
13	11/12/99	Tube Leak	46.62
14	12/18/99	Tube Leak	10.13
15			
16		**COLSTRIP UNIT #1**	
17	01/06/99	Tube Leak	25.67
18	03/20/99	Repair Air preheater	49.60
19	03/22/99	Booster Pump	1.00
20	03/22/99	Power Interruption	0.93
21	04/27/99	Repair Leak	73.27
22	05/05/99	Vacuum Loss	0.85
23	05/05/99	Low boiler Water Circulation	0.60
24	05/21/99	Annual Overhaul	768.55
25	06/23/99	Turbine Trip	14.77
26	06/23/99	Fan Outlet Gate	9.00
27	06/24/99	Tube Leak	46.47
28	06/26/99	Suction Pressure Trip	5.15
29	06/28/99	Tube Leak	67.83
30	07/04/99	Scheduled Tests	2.58
31	08/24/99	Tube Leak	22.15
32	08/25/99	System load gear replacement	10.52
33	09/26/99	Fire	333.55
34	10/10/99	Unit Trip	5.00
35	10/10/99	Drain and Refill Boiler	15.28
36	10/14/99	Transformer Trip	11.43
37	10/16/99	Tube Leak	19.48
38	10/31/99	Transformer Trip	37.22
39	11/29/99	Pressure Loss	1.57
40	12/6/99	Transformer Trip	3.68
41	12/25/99	Tube Leak	20.33
42		**COLSTRIP UNIT #2**	
43	01/05/99	Power Loss	2.00
44	01/05/99	Tube Leak	100.53
45	01/09/99	Scanner Failure	0.55
46	01/09/99	Scanner Failure	0.47
47	02/02/99	Loss of 500KV Lines	3.10
48	02/25/99	Tube Failure	41.73
49	04/28/99	Loss of 500KV Lines	0.90
50	04/29/99	Loss of 500KV Lines	0.77
51	05/12/99	Scheduled Outage	132.35
52	05/18/99	Valve Stem	2.58
53	06/09/99	Clean Air Preheaters	95.8
54	06/14/99	Vacuum Trip	0.52

Sch. 34	cont.	**OUTAGES**	
	Start Date	Description	Duration(Hrs)
1		**COLSTRIP #2**	
2	07/13/99	Tube Replacement	96.22
3	09/26/99	230KV Line Failed	188.67
4			
5		**COLSTRIP #3**	
6	01/11/99	Tube Leak	107.70
7	01/15/99	Weld Failure	2.00
8	01/15/99	Switchyard Failure	16.68
9	02/02/99	Loss of 500KV Lines	2.00
10	02/02/99	Tube Leak	70.40
11	02/19/99	Tube Leak	97.48
12	02/23/99	Tube Leak	12.00
13	03/01/99	Tube Leak	61.83
14	03/14/99	Stuck Valve	22.00
15	03/15/99	Tripped while testing	0.55
16	04/28/99	Loss of 500KV Lines	1.27
17	05/14/99	Scheduled Outage	225.72
18	06/02/99	Low Pressure	1.07
19	07/08/99	Tube Leak	49.40
20	07/15/99	Low Pressure	2.00
21	07/15/99	Repair Seal	77.83
22	08/12/99	Ground Fault Trip	2.93
23	08/25/99	High Vibration	30.02
24	09/20/99	500KV Line Maintenance	11.73
25	09/20/99	Modify Gearbox	63.88
26	09/26/99	Drum Pressure	0.62
27	10/09/99	False ATR	762.00
28	10/21/99	Coverter Card	1.63
29	11/01/99	Boiler Roof Repair	85.10
30	11/07/99	Tube Leak	48.30
31	11/18/99	Regulator	1.77
32			
33		**COLSTRIP UNIT #4**	
34	01/13/99	Repair Tube Leak	35.27
35	01/15/99	Low Drum Level	1.35
36	02/02/99	Loss of 500KV Lines	1.58
37	02/02/99	Loss of Oil Pressure	0.33
38	03/04/99	Tube Leak	68.87
39	03/08/99	Faulty Pressure Switch	0.53
40	04/28/99	Loss of 500KV Lines	2.50
41	04/29/99	Loss of 500KV Lines	0.35
42	05/07/99	Loss of Fan	0.90
43	06/18/99	Scheduled Outage	483.82
44	07/09/99	Low BWCP	2.77
45	08/07/99	Tube Leak	27.25
46	08/08/99	Low Drum Level	0.50
47	10/09/99	False Trip Signal	1.52
48	12/03/99	Tube Leak	51.22
49			
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MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS - ELECTRIC 1/

Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings MW	Planned Savings MWH	Achieved Savings MW	Achieved Savings MWH	Difference MW	Difference MWH
Residential									
Technologies for the Home (SGC) 2/	$0	$122,234	-100%	N/A	N/A	0.000	0	0.000	0
Free Weatherization (low income)	425,713	396,632	7%	N/A	N/A	0.540	924	0.540	924
Fuel Switching	0	288,000	-100%	N/A	N/A	0.000	0	0.000	0
E+ Audit Program 3/	851,219	989,727	-14%	N/A	N/A	0.572	3,120	0.572	3,120
Commercial/Industrial									
Business Partners Retrofit	26,694	647,950	-96%	N/A	N/A	0.019	274	0.019	274
Business Partners New 4/	0	120,577	-100%	N/A	N/A	0.000	0	0.000	0
Audit Strategy 3/	0	104,079	-100%	N/A	N/A	0.000	0		
Motors	0	96,333	-100%	N/A	N/A	0.000	0	0.000	0
Lighting	77,410	871,879	-91%	N/A	N/A	0.206	732	0.206	732
Northwest Energy Efficiency Alliance /5	518,123	382,515	35%	N/A	N/A	N/A	457	0.000	457
TOTAL	$1,899,159	$4,019,926	-53%	0.00	0	1.34	5,507	1.34	5,507

1/ Detailed information regarding program initiation, program projected life, program participants and program conservation units may be obtained from the NU-TRACK Report or the Efficiency Plus Annual Report.

2/ Under DSM Super Good Cents (SGC) had been incorporated into Technologies for the Home. 1999 activities included a portion of programs offered through contractors of the Northwest Energy Efficiency Alliance.

3/ Small commercial audit pilot program expenditures are included.

4/ New construction activity is included in the Business partners program - retrofit

5/ Northwest Energy Efficiency Alliance programs do not report capacity savings and include infrastructure investments which may not provide direct resource savings for reporting urposes

OVERALL NOTE: In 1999, MPC moved from DSM to Universal System Benefits programs making comparisons difficult. The transition resulted in a reduction of activity in the commercial sector in 1999. In addition to the funds spend in 1999, additional USB revenues collected in 1999 have been committed to qualifying activities in 2000. These investments do not include the funds or results related to self-directed activities by qualifying USB Large Customers.
USB funds are directed to low income energy assistance, conservation, market transformation, renewable resources, and research and development. Additional USB funds collected in 2000 will be directed to residential and commercial conservation and market transformation funds.

SOURCE: 1999 Montana Power USB Report filed with DOR

Sch. 36

MONTANA CONSUMPTION AND REVENUES - ELECTRIC (EXCLUDES UNIT 4 & YNP)

	Operating Revenues		MWH Sold		Average Customers	
	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
Sales of Electricity						
Residential	$129,891,846	$127,753,410	1,826,574	1,941,729	232,328	231,768
Commercial & Industrial	217,470,674	248,735,906	5,322,257	5,009,762	48,876	48,339
Public Street & Highway Lighting	6,018,307	5,637,841	65,670	33,535	3,146	2,866
Other Sales to Public Authorities	1,017,185	4,066,604	36,377	123,381	104	105
Sales to Cooperatives	18,087,200	18,895,905	513,913	522,249	54	60
Sales to Other Utilities	90,829,362	51,592,582	3,816,163	2,155,784	59	37
Interdepartmental	613,054	746,062	12,022	13,934	236	225
TOTAL SALES	$463,927,628	$457,428,310	11,592,976	9,800,374	284,803	283,400

NB: Other Sales to Public Authorities and Sales to Cooperatives are based on Ferc Form 1, pp. 310.1 - 310.5. Residential and Commercial & Industrial of the current and previous years exclude Yellowstone volumes and customers. For that reason, the previous year's are different from those stated in the 1998 schedule 36.