YEAR 1999

ANNUAL REPORT

OF

The Montana Power Company

NATURAL GAS UTILITY

The Montana Power Company

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

Revised June 5, 2000

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

Sch. 2 cont. **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
28						
29						
30						
31						
32						
33						
34						

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
Nonutility Subsidiaries					
Western Energy Company	Sales of Electricity	Tariff Schedules	$1,819,670	0.25%	$1,819,670
	Project Services	Actual Costs Incurred	252,656	0.03%	252,656
North American Resources	Gas Transportation	Monthly Bid Rate(FERC Tariff) & Fixed Rate (NEB)	604	0.00%	604
Touch America, Inc.	Sales of Gas & Electricity	Tariff Schedules	27,923	0.00%	27,923
Rosebud SynCoal	Sale of Coal	Actual Costs Incurred	78,597	0.01%	78,597
Total Nonutility Subsidiaries			$2,179,450	0.30%	$2,179,450
Total Nonutility Subsidiaries Expenses			$730,547,000		
Utility Subsidiaries					
Colstrip Community Services	Project Services	Actual Costs Incurred	$38,828	0.01%	$38,828
Total Utility Subsidiaries			$38,828	0.01%	$38,828
Total Utility Subsidiaries Expenses			$455,171,000		
TOTAL AFFILIATE TRANSACTIONS			$2,218,278		$2,218,278

Sch. 8	MONTANA UTILITY INCOME STATEMENT - NATURAL GAS (INCLUDES CMP) - 1/					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
2	400 Operating Revenues	$104,402,989	$129,285	$104,273,704	$106,624,953	-2.21%
4	**Total Operating Revenues**	$104,402,989	$129,285	$104,273,704	$106,624,953	-2.21%
6	**Operating Expenses**					
8	401 Operation Expense	$62,803,674	$68,272	62,735,402	$64,097,882	-2.13%
9	402 Maintenance Expense	5,720,938	1,910	5,719,028	5,077,923	12.63%
10	403 Depreciation Expense	8,259,219	3,629	8,255,590	8,464,539	-2.47%
11	404-405 Amort. & Depletion of Gas Plant	958,992	183	958,809	158,761	503.93%
12	406 Amort. of Plant Acquisition Adj.					
13	407.1 Amort. of Property Losses,					
14	Unrecovered Plant, and					
15	Regulatory Study Costs					
16	408.1 Taxes Other Than Income Taxes	14,282,372	26,512	14,255,860	14,011,150	1.75%
17	409.1 Income Taxes-Federal	(191,083)	10,772	(201,855)	278,495	-172.48%
18	-Other	(79,056)	384	(79,440)	(118,152)	32.76%
19	410.1 Deferred Income Taxes-Dr.	246,353		246,353	124,876	97.28%
20	411.1 Deferred Income Taxes-Cr.		(1,124)	1,124	0	***
21	411.4 Investment Tax Credit Adj.	(134,861)		(134,861)	(115,753)	-16.51%
22	411.6 Gain from Disposition of Property					
23	411.7 Loss from Disposition of Property					
25	**Total Operating Expenses**	$91,866,548	$110,538	$91,756,010	$91,979,721	-0.24%
26	**NET OPERATING INCOME**	$12,536,441	$18,747	$12,517,694	$14,645,232	-14.53%

Sch. 9	MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)				
Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
Core Distribution Business Units (DBUs)					
440 Residential	$60,420,611		$60,420,611	$61,446,308	-1.67%
442.1 Commercial	27,376,692		27,376,692	30,120,125	-9.11%
442.2 Industrial Firm	1,254,911		1,254,911	1,371,859	-8.52%
445 Public Authorities	(11,586)		(11,586)	237,205	-104.88%
448 Interdepartmental Sales	190,263		190,263	201,366	-5.51%
491.2 CNG Station	10,469		10,469	16,569	-36.82%
Total Sales to Core DBUs	$89,241,360	$0	$89,241,360	$93,393,432	-4.45%
447 Sales for Resale	$740,736	$129,285	$611,451	$606,470	0.82%
442.2 Interruptible Industrial					
Total Sales of Natural Gas	$89,982,096	$129,285	$89,852,811	$93,999,902	-4.41%
Transportation					
489 Transportation (inc. CMP)	$12,137,714		$12,137,714	$12,981,466	-6.50%
442.2 Sales Subscription					
495 Storage	2,079,928		2,079,928	2,368,767	-12.19%
Total Revenues From Transportation	$14,217,642	$0	$14,217,642	$15,350,233	-7.38%
Other Operating Revenue					
Montana Power Company	$203,251		$203,251	($2,725,182)	107.46%
Total Other Operating Revenue	$203,251	$0	$203,251	($2,725,182)	107.46%
TOTAL OPERATING REVENUE	$104,402,989	$129,285	$104,273,704	$106,624,953	-2.21%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1	**Production Expenses**					
2	**Production & Gathering-Operation**					
3	735 Misc. Production Expense					
4	750 Supervision & Engineering	$36,593	($36)	$36,629	$46,590	-21.38%
5	751 Maps & Records	0		0	(247)	100.00%
6	752 Gas Wells Expenses	3,394	3,180	214	237	-9.74%
7	753 Field Lines Expenses	0	0	0	0	0.00%
8	754 Field Compressor Station Expense	8,276	7,520	756	460	64.24%
9	755 Field Comp. Station Fuel & Power	1,909	935	974	767	27.11%
10	756 Field Meas. & Reg. Station Expense	3,176	2,800	376	840	-55.26%
11	757 Dehydration Expense	2,172	2,159	13	382	-96.55%
12	758 Gas Well Royalties	9,536	9,536	0	34,227	-100.00%
13	759 Other Expenses	4,811	2,011	2,800	2,499	12.07%
14	760 Rents	0		0	0	0.00%
15	**Total Oper.-Production & Gathering**	$69,867	$28,104	$41,763	$85,754	-51.30%
16	**Production & Gathering-Maintenance**					
17	761 Supervision & Engineering			$0	$0	-
18	762 Structures & Improvements	$0	$0	0	0	-
19	763 Producing Gas Wells			0	0	-
20	764 Field Lines	(7)	(7)	0	0	-
21	765 Field Compressor Station Equip.	594	594	0	0	-
22	766 Field Meas. & Reg. Station Equip.			0	0	-
23	767 Purification Equipment	(3)	(3)	0	0	-
24	768 Drilling & Cleaning Equipment					-
25	769 Other Equipment			0	0	-
26	**Total Maint.-Production & Gathering**	$585	$585	$0	$0	-
27	**Total Production & Gathering**	$70,452	$28,689	$41,763	$85,754	-51.30%
28	**Products Extraction-Operation**					
29	770 Supervision & Engineering	$0		$0	$0	-
30	771 Labor			0	0	-
31	772 Gas Shrinkage					-
32	773 Fuel					-
33	774 Power			0	0	-
34	775 Materials			0	0	-
35	776 Supplies & Expenses			0	0	-
36	777 Gas Processed by Others					-
37	778 Royalties on Products Extracted					-
38	779 Marketing Expenses			0	0	-
39	780 Products Purchased for Resale					-
40	781 Variation in Products Inventory					-
41	782 Extracted Products Used by Util.-Cr.					-
42	783 Rents					-
43	**Total Operation-Products Extraction**	$0	$0	$0	$0	-
44	**Products Extraction-Maintenance**					
45	784 Supervision & Engineering			$0	$0	-
46	785 Structures & Improvements			0	0	-
47	786 Extraction & Refining Equipment			0	0	-
48	787 Pipe Lines			0	0	-
49	788 Extracted Prod. Storage Equip.			0	0	-
50	789 Compressor Equipment			0	0	-
51	790 Gas Meas. & Reg. Equipment			0	0	-
52	791 Other Equipment			0	0	-
53	**Total Maintenance-Products Extraction**	$0	$0	$0	$0	-
54	**Total Products Extraction**	$0	$0	$0	$0	-

Sch. 10	(cont.) MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1	**Production Expenses-cont.**					
2						
3	**Exploration & Development-Operation**					
4	795 Delay Rentals	$0		$0	($2,899)	100.00%
5	796 Nonproductive Well Drilling			0	0	-
6	797 Abandoned Leases			0	0	-
7	798 Other Exploration					
8	799 Loss on Disposition of Property					
9	**Total Exploration & Development**	$0	$0	$0	($2,899)	100.00%
10						
11	**Other Gas Supply Expense-Operation**					
12	800 NG Wellhead Purchases	$15,943,938	$16,380	$15,927,558	$16,017,303	-0.56%
13	800.1 NG Wellhead Purchases, Intraco.	16,634,023		$16,634,023	$18,857,825	-11.79%
14	801 NG Field Line Purchases					
15	802 NG Gasoline Plant Outlet Purchases					
16	803 NG Transmission Line Purchases	802,754		802,754	(520,705)	254.17%
17	804 NG City Gate Purchases					
18	805 Other Gas Purchases					
19	805.1 Purchased Gas Cost Adjustments	421,862		421,862	1,418,867	-70.27%
20	805.2 Incremental Gas Cost Adjustments					
21	805.3 Deferred Gas Cost Adjustments				(164,818)	100.00%
22	806 Exchange Gas					
23	807.1 Well Expenses-Purchased Gas	232,893	(3)	232,896	182,691	27.48%
24	807.2 Purch. Gas Meas. Stations-Oper.	45,230	(5)	45,235	52,985	-14.63%
25	807.3 Purch. Gas Meas. Stations-Maint.	71,975		71,975	33,341	115.88%
26	807.4 Purch. Gas Calculations Expenses	22,279		22,279	43,739	-49.06%
27	807.5 Other Purchased Gas Expenses	120,148		120,148	231,785	-48.16%
28	808.1 Gas Withdrawn from Storage -Dr.	10,518,341		10,518,341	15,484,606	-32.07%
29	808.2 Gas Delivered to Storage -Cr.					
30	809.2 Delivery of Gas for Processing-Cr.	(11,558,935)		(11,558,935)	(19,241,686)	39.93%
31	810 Gas Used-Comp. Station Fuel-Cr.					
32	811 Gas Used-Products Extraction-Cr.					
33	812 Gas Used-Other Utility Oper.-Cr.					
34	813 Other Gas Supply Expenses	0		0	0	-
35	**Total Other Gas Supply Expenses**	$33,254,509	$16,372	$33,238,137	$32,395,933	2.60%
36	**Total Production Expenses**	$33,324,961	$45,061	$33,279,900	$32,478,788	2.47%
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Sch. 10	(cont.) MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1	**Storage, Terminaling & Processing Exp.**					
2						
3	**Underground Storage-Operation**					
4	814 Supervision & Engineering	$317,243		$317,243	$307,962	3.01%
5	815 Maps & Records	100,357		100,357	85,247	17.73%
6	816 Wells	80,122		80,122	105,949	-24.38%
7	817 Lines	12,765		12,765	15,412	-17.18%
8	818 Compressor Station	110,166		110,166	92,838	18.66%
9	819 Compressor Station Fuel & Power	11,052		11,052	12,322	-10.31%
10	820 Measuring & Regulating Station	30,507		30,507	34,947	-12.71%
11	821 Purification	47,345		47,345	48,668	-2.72%
12	822 Exploration & Development					
13	823 Gas Losses					
14	824 Other Expenses	93,916		93,916	117,259	-19.91%
15	825 Storage Well Royalties	122,537		122,537	136,023	-9.91%
16	826 Rents	(500)		(500)	361	-238.66%
17	**Total Operation-Underground Storage**	$925,510	$0	$925,510	$956,988	-3.29%
18						
19	**Underground Storage-Maintenance**					
20	830 Supervision & Engineering	$57,349		$57,349	$93,191	-38.46%
21	831 Structures & Improvements	14,183		14,183	940	1409.37%
22	832 Reservoirs & Wells	36,728		36,728	6,912	431.37%
23	833 Lines	47,749		47,749	62,461	-23.55%
24	834 Compressor Station Equipment	155,662		155,662	136,765	13.82%
25	835 Meas. & Reg. Station Equipment	37,707		37,707	37,090	1.66%
26	836 Purification Equipment	9,323		9,323	11,734	-20.55%
27	837 Other Equipment	9,178		9,178	6,990	31.31%
28	**Total Maintenance-Underground Storage**	$367,879	$0	$367,879	$356,082	3.31%
29	**Total Underground Storage Expenses**	$1,293,389	$0	$1,293,389	$1,313,070	-1.50%
30						
31	**Other Storage-Operation**					
32	840 Supervision & Engineering					
33	841 Labor and Expenses					
34	842 Rents					
35	842.1 Fuel					
36	842.2 Power					
37	842.3 Gas Losses					
38	**Total Operation-Other Storage**	$0	$0	$0	$0	-
39						
40	**Other Storage-Maintenance**					
41	843.1 Supervision & Engineering					
42	843.2 Structures & Improvements					
43	843.3 Gas Holders					
44	843.4 Purification Equipment					
45	843.6 Vaporizing Equipment					
46	843.7 Compressor Equipment					
47	843.8 Measuring & Regulating Equipment					
48	843.9 Other Equipment					
49	**Total Maintenance-Other Storage**	$0	$0	$0	$0	-
50	**Total Other Storage Expenses**	$0	$0	$0	$0	-
51	**Total Storage, Terminaling & Processing**	$1,293,389	$0	$1,293,389	$1,313,070	-1.50%
52						
53						

Sch. 10	(cont.) MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1	**Transmission Expenses**					
2	**Transmission-Operation**					
3	850 Supervision & Engineering	$792,099	($71)	$792,170	$758,616	4.42%
4	851 System Control & Load Dispatching	476,948		476,948	481,298	-0.90%
5	852 Communications System					
6	853 Compressor Station Labor & Expens	$ 312,776		312,776	243,762	28.31%
7	854 Gas for Compressor Station Fuel			0		
8	855 Other Fuel & Power for Comp. Stat.	60,957		60,957	236,434	-74.22%
9	856 Mains	507,837	5,010	502,828	184,920	171.92%
10	857 Measuring & Regulating Station	296,389	327	296,063	336,346	-11.98%
11	858 Transmission & Comp.-By Others	103,032		103,032	104,613	-1.51%
12	859 Other Expenses	832,438	400	832,038	940,375	-11.52%
13	860 Rents	118,086	1,877	116,210	111,119	4.58%
14	**Total Operation-Transmission**	$3,500,563	$7,542	$3,493,021	$3,397,484	2.81%
15	**Transmission-Maintenance**					
16	861 Supervision & Engineering	$306,691		306,691	$435,471	-29.57%
17	862 Structures & Improvements	78,989		78,989	59,739	32.22%
18	863 Mains	814,806	1,154	813,652	1,066,645	-23.72%
19	864 Compressor Station Equipment	722,275		722,275	517,927	39.45%
20	865 Meas. & Reg. Station Equipment	417,156	170.3	416,986	429,991	-3.02%
21	866 Communication Equipment					
22	867 Other Equipment	20,743		20,743	19,858	4.46%
23	**Total Maintenance-Transmission**	$2,360,661	$1,325	$2,359,336	$2,529,632	-6.73%
24	**Total Transmission Expenses**	$5,861,224	$8,867	$5,852,357	$5,942,913	-1.52%
25	**Distribution Expenses**					
26	**Distribution-Operation**					
27	870 Supervision & Engineering	$ 670,150		670,150	$554,631	20.83%
28	871 Distribution Load Dispatching					
29	872 Compressor Station Labor & Expens	10,049		10,049	14,364	-30.04%
30	873 Compressor Station Fuel and Power	15		15	84	-82.31%
31	874 Mains and Services	1,346,283		1,346,283	1,486,361	-9.42%
32	875 Meas. & Reg. Station-General	42,437		42,437	18,567	128.56%
33	876 Meas. & Reg. Station-Industrial	9,481		9,481	22,021	-56.95%
34	877 Meas. & Reg. Station-City Gate	94,829		94,829	110,240	-13.98%
35	878 Meter & House Regulator	637,594		637,594	704,262	-9.47%
36	879 Customer Installations	3,559,160		3,559,160	3,778,928	-5.82%
37	880 Other Expenses	612,670		612,670	634,348	-3.42%
38	881 Rents	6,119		6,119	17,276	-64.58%
39	**Total Operation-Distribution**	$6,988,787	$0	$6,988,787	$7,341,082	-4.80%
40	**Distribution-Maintenance**					
41	885 Supervision & Engineering	$376,446		$376,446	$470,273	-19.95%
42	886 Structures & Improvements	14,613		14,613	34,174	-57.24%
43	887 Mains	683,744		683,744	809,781	-15.56%
44	888 Compressor Station Equipment					
45	889 Meas. & Reg. Station Exp.-General	40,045		40,045	75,876	-47.22%
46	890 Meas. & Reg. Station Exp.-Industrial	693		693	1,775	-60.96%
47	891 Meas. & Reg. Station Exp.-City Gate	5,710		5,710	23,815	-76.03%
48	892 Services	387,242		387,242	460,597	-15.93%
49	893 Meters & House Regulators	217,824		217,824	310,324	-29.81%
50	894 Other Equipment	4,062		4,062	5,594	-27.39%
51	**Total Maintenance-Distribution**	$1,730,377	$0	$1,730,377	$2,192,209	-21.07%
52	**Total Distribution Expenses**	$8,719,164	$0	$8,719,164	$9,533,291	-8.54%
53						

Sch. 10	(cont.) MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1	**Customer Accounts Expenses**					
2	**Customer Accounts-Operation**					
3	901 Supervision			$0	$0	0.00%
4	902 Meter Reading	559,250		559,250	884,949	-36.80%
5	903 Customer Records & Collection	2,448,417		2,448,417	1,203,911	103.37%
6	904 Uncollectible Accounts	384,124		384,124	368,390	4.27%
7	905 Miscellaneous Customer Accounts	160		160	222	-27.61%
8	**Total Customer Accounts Expenses**	$3,391,951	$0	$3,391,951	$2,457,471	38.03%
9						
10	**Customer Service & Information Expenses**					
11	**Customer Service-Operation**					
12	907 Supervision	$27,825		$27,825	$26,118	6.53%
13	908 Customer Assistance	821,564	$0	821,564	1,145,831	-28.30%
14	909 Inform. & Instructional Advertising	195,857		195,857	409,887	-52.22%
15	910 Misc. Customer Service & Inform.	3,617		3,617	3,661	-1.20%
16	**Total Customer Service & Information Exp.**	$1,048,863	$0	$1,048,863	$1,585,497	-33.85%
17						
18	**Sales Expenses**					
19	**Sales-Operation**					
20	911 Supervision	$171,343		$171,343	$174,737	-1.94%
21	912 Demonstrating & Selling	489,535		489,535	806,365	-39.29%
22	913 Advertising	25,499	$230	25,269	100,378	-74.83%
23	916 Miscellaneous Sales	3,001		3,001	3,263	-8.02%
24	**Total Sales Expenses**	$689,378	$230	$689,148	$1,084,743	-36.47%
25						
26	**Administrative & General Expenses**					
27	**Admin. & General - Operation**					
28	407 Amortization of Regulatory Asset	$142,832		$142,832	$2,376,199	-93.99%
29	920 Administrative & General Salaries	6,346,524	$2,258	6,344,266	$6,198,938	2.34%
30	921 Office Supplies & Expenses	1,795,661	(1,149)	1,796,810	1,527,397	17.64%
31	922 Administrative Exp. Transferred-Cr.	(894,486)		(894,486)	(363,307)	-146.21%
32	923 Outside Services Employed	1,519,137	8,204	1,510,933	1,052,460	43.56%
33	924 Property Insurance	80,243		80,243	57,934	38.51%
34	925 Legal & Claim Department	646,997	4,701	642,296	756,899	-15.14%
35	926 Employee Pensions & Benefits	(222,916)	1,597	(224,513)	(587,324)	61.77%
36	927 Franchise Requirements					
37	928 Regulatory Commission Expenses	74,163	(4)	74,167	52,653	40.86%
38	929 Duplicate Charges-Cr.					
39	930 Miscellaneous General Expenses	1,907,240	416	1,906,824	1,780,183	7.11%
40	931 Rents	1,538,851		1,538,851	854,053	80.18%
41	**Total Operation-Admin. & General**	$12,934,246	$16,024	$12,918,222	$13,706,085	-5.75%
42	**Admin. & General - Maintenance**					
43	935 General Plant	$1,261,437	$0	$1,261,437	$1,089,745	15.76%
44	**Total Admin. & General Expenses**	$14,195,683	$16,024	$14,179,659	$14,795,830	-4.16%
45	**TOTAL OPER. & MAINT. EXPENSES**	$68,524,612	$70,182	$68,454,430	$69,175,805	-1.04%
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Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)			
	Description	Last Year	This Year	% Change
	Federal Taxes			
	Social Security Old Age	$1,252,467	$1,288,101	2.85%
	Social Security Unemployment	40,098	89,397	122.95%
	Medicare	347,108	330,461	-4.80%
	Montana Taxes			
	Real Estate & Personal Property	12,905,266	13,264,874	2.79%
	Social Security Unemployment	55,004	7,416	-86.52%
	Old Fund Liability	121,823	(546)	-100.45%
	Severance	0	408	-
	Consumer Counsel	84,618	98,976	16.97%
	Public Service Commission	253,563	266,849	5.24%
	Resource Indemnity	311	0	-100.00%
	City Licenses	2,907	3,280	12.85%
	Production	60,071	36,005	-40.06%
	Crow Tribe RR and Utility Tax	0	66,198	-
	District of Columbia Taxes			
	Social Security Unemployment	173	72	-58.38%
	Personal Property	55	44	-19.93%
	Canadian Taxes			
	Ad Valorem	53,889	53,642	-0.46%
	Other			
	Payroll Tax Credit	(1,166,203)	(1,249,320)	-7.13%
	TOTAL TAXES OTHER THAN INCOME	$14,011,150	$14,255,860	1.75%
		Test	0	
	Glacier Gas taxes other than income		26,512	

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			

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

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

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

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	
45				
46				
47				
48				
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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					
Name/Title	Base Salary 1/	Other Comp. 2/		Total Comp.	Total Comp. Last Year	% Change
R. P. Gannon	$399,946	$8,654	<A			
Chairman of the Board		5,763	<B			
President and Chief Executive		263,671	<C			
Officer		126,000	<D			
		83,426	<E			
		2,264	<G			
		338	<H			
		481	<I			
		550	<J	$891,093	$1,084,537	-18%
R.F. Cromer	$164,800	$33,488	<A			
Executive Vice President &		6,400	<B			
Chief Operating Officer, Energy		117,187	<C			
Supply Division		84,000	<D			
		671	<G			
		573	<H			
		330	<I			
				$407,449	$310,019	31%
J. D. Haffey	$176,190	$19,000	<A			
Executive Vice President &		6,400	<B			
Chief Operating Officer, Energy		115,356	<C			
Services Division		84,000	<D			
		539	<G			
		60	<H			
		530	<I			
		2,769	<J			
				$404,844	$431,139	-6%
J. P. Pederson	$200,022	$6,400	<B			
Vice Chairman & Chief Financial		112,915	<C			
Officer		60,000	<D			
		485,438	<E			
		1,139	<G			
		374	<I			
				$866,288	$285,007	204%
W. S. Dee	$176,485	$6,400	<B			
Vice President, Marketing		65,918	<C			
		182	<G			
		319	<H			
		426	<I	$249,730	$216,616	15%

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. 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."

Cash and Cash Equivalents

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.

Storm Damage and Environmental Remediation Costs

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.

Income Taxes

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."

Asset Impairment

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.

Comprehensive Income

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:

Assets Sold

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	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	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	December 31 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%

[redacted]

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 - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1	**Intangible Plant**					
2	2301 Organization	$39,051	$17,420	$21,631	$21,631	0.00%
3	2302 Franchises and Consents	258,020		258,020	258,020	0.00%
4	2303 Miscellaneous Intangible Plant	424,863	6,736	418,127	323,204	29.37%
5	**Total Intangible Plant**	721,934	24,156	697,778	602,855	15.75%
6						
7	**Production Plant**					
8						
9	**Production and Gathering Plant**					
10	2325 Land and Land Rights	566,007	566,007	0	0	0.00%
11	2326 Gas Well Structures			0	0	0.00%
12	2327 Field Compressor Station Struct.			0	0	0.00%
13	2328 Field Meas. & Reg. Station Struct.	60,700	60,700	0	0	0.00%
14	2329 Other Structures	5,296	5,296	0	0	0.00%
15	2330 Producing Gas Wells-Well Constr.	903,080	903,080	0	0	0.00%
16	2331 Producing Gas Wells-Well Equip.	64,046	64,046	0	0	0.00%
17	2332 Field Lines and Equipment	121,531	121,531	0	0	0.00%
18	2333 Field Compressor Station Equip.	200,739	200,739	0	0	0.00%
19	2334 Field Meas. & Reg. Station Equip.	90,931	90,931	0	0	0.00%
20	2335 Drilling and Cleaning Equipment			0	0	0.00%
21	2336 Purification Equipment	12,107	12,107	0	0	0.00%
22	2337 Other Equipment	1,402	1,402	0	0	0.00%
23	2338 Unsuccessful Explor. & Devel. Cost					
24	**Total Production and Gathering Plant**	2,025,838	2,025,839	0	0	0.00%
25						
26	**Products Extraction Plant**					
27	2340 Land and Land Rights	-		0	0	0.00%
28	2341 Structures and Improvements	-		0	0	0.00%
29	2342 Extraction and Refining Equipment	-		0	0	0.00%
30	2343 Pipe Lines	-		0	0	0.00%
31	2344 Extracted Products Storage Equip.	-		0	0	0.00%
32	2345 Compressor Equipment	-		0	0	0.00%
33	2346 Gas Measuring & Regulating Equip	-		0	0	0.00%
34	2347 Other Equipment	-		0	0	0.00%
35	**Total Products Extraction Plant**	0	0	0	0	0.00%
36	**Total Production Plant**	2,025,838	2,025,839	0	0	0.00%
37						
38	**Storage and Processing Plant**					
39						
40	**Underground Storage Plant**					
41	2350 Land and Land Rights	3,938,482		3,938,482	3,925,669	0.33%
42	2351 Structures and Improvements	1,901,943		1,901,943	1,866,856	1.88%
43	2352 Wells	7,051,311		7,051,311	6,707,117	5.13%
44	2353 Lines	6,180,553		6,180,553	6,022,666	2.62%
45	2354 Compressor Station Equipment	4,883,939		4,883,939	4,883,939	0.00%
46	2355 Measuring & Regulating Equip.	1,526,497		1,526,497	1,452,739	5.08%
47	2356 Purification Equipment	223,950		223,950	223,950	0.00%
48	2357 Other Equipment	827,326		827,326	809,178	2.24%
49	**Total Underground Storage Plant**	26,534,000	0	26,534,000	25,892,114	2.48%
50	**Other Storage Plant**					
51	2360 - 2363 Not Applicable					
52	**Total Other Storage Plant**	0	0	0	0	0.00%
53	**Total Storage and Processing Plant**	26,534,000	0	26,534,000	25,892,114	2.48%

MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)

	Account Number & Title	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	% Change
1						
2	**Transmission Plant**					
3	2365 Rights of Way	5,286,789	12,857	5,273,932	5,036,470	4.71%
4	2366 Structures and Improvements	7,849,504		7,849,504	6,746,657	16.35%
5	2367 Mains	127,489,579	431,939	127,057,640	122,311,195	3.88%
6	2368 Compressor Station Equipment	14,737,093		14,737,093	14,715,157	0.15%
7	2369 Meas. & Reg. Station Equipment	8,909,201		8,909,201	3,868,267	130.32%
8	2370 Communication Equipment	66,875		66,875	66,875	0.00%
8	2371 Other Equipment	73,320		73,320	59,741	22.73%
9	**Total Transmission Plant**	164,412,361	444,796	163,967,565	152,804,362	7.31%
10						
11	**Distribution Plant**					
12	2374 Land and Land Rights	859,272		859,272	973,709	-11.75%
13	2375 Structures and Improvements	211,344		211,344	1,225,468	-82.75%
14	2376 Mains	66,662,914		66,662,914	64,476,647	3.39%
15	2377 Compressor Station Equipment	-				
16	2378 M&R Station Equip.-General	2,043,364		2,043,364	2,188,254	-6.62%
17	2379 M&R Station Equip.-City Gate	341,128		341,128	5,135,269	-93.36%
18	2380 Services	52,060,771		52,060,771	48,893,742	6.48%
19	2381 Customers Meters and Regulators	14,876,111	60	14,876,051	14,185,930	4.86%
20	2382 Meter Installations	9,324,408		9,324,408	8,443,473	10.43%
21	2383 House Regulators	-				
22	2384 House Regulator Installations	-				
23	2385 M&R Station Equip.-Industrial	45,085		45,085	45,085	0.00%
24	2386 Other Prop. on Customers' Premise	-				
25	2387 Other Equipment	(1,518)		(1,518)	6,413	-123.67%
26	**Total Distribution Plant**	146,422,878	60	146,422,819	145,573,990	0.58%
27						
28	**General Plant**					
29	2389 Land and Land Rights	104,550		104,550	104,550	0.00%
30	2390 Structures and Improvements	677,335		677,335	666,217	1.67%
31	2391 Office Furniture and Equipment	1,781,286		1,781,286	1,857,584	-4.11%
32	2392 Transportation Equipment	6,299,990		6,299,990	6,281,528	0.29%
33	2393 Stores Equipment	12,616		12,616	13,522	-6.70%
34	2394 Tools, Shop & Garage Equipment	3,791,138		3,791,138	3,727,927	1.70%
35	2395 Laboratory Equipment	826,005		826,005	802,373	2.95%
36	2396 Power Operated Equipment	1,707,902		1,707,902	1,737,921	-1.73%
37	2397 Communication Equipment	1,109,349	23,237	1,086,112	1,083,539	0.24%
38	2398 Miscellaneous Equipment	46,947		46,947	50,291	-6.65%
39	2399 Other Tangible Property	-		0	0	0.00%
40	**Total General Plant**	16,357,117	23,237	16,333,880	16,325,452	0.05%
41	**Total Gas Plant in Service**	356,474,129	2,518,088	353,956,042	341,198,773	3.74%
42						
43	4101 Gas Plant Allocated from Common	13,447,245		13,447,245	14,134,647	-4.86%
44	2105 Gas Plant Held for Future Use	8,984		8,984	46,817	-80.81%
45	2107 Gas Construction Work in Progress	235,913		235,913	252,400	-6.53%
46	2117 Gas in Underground Storage	44,877,231		44,877,231	47,145,562	-4.81%
47						
48	**Total Gas Plant**	$415,043,501	$2,518,088	$412,525,414	$402,778,199	2.42%
49						
50						
51						
52						
53						

Sch. 20

MONTANA DEPRECIATION SUMMARY - NATURAL GAS (INCLUDES CMP)

Functional Plant Class	Montana Plant Cost	This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	Current Avg. Rate
Accumulated Depreciation						
Production and Gathering			$1,855,978	$0	$0	0.00%
Underground Storage	26,534,000	12,257,165		12,257,165	11,569,814	2.67%
Other Storage						
Transmission	163,967,565	52,989,919	435,984	52,553,935	48,237,091	1.76%
Distribution	146,422,819	47,491,722	59	47,491,663	45,480,942	3.09%
General and Intangible	17,031,658	9,094,805	10,365	9,084,440	8,476,527	6.79%
Common	13,447,245	2,674,764		2,674,764	2,955,977	4.25%
TOTAL DEPRECIATION	$367,403,287	$124,508,375	$2,302,386	$124,061,967	$116,720,351	2.54%

Sch. 21 **MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS (INCLUDES CMP)**

Account Number & Title		This Year Cons. Utility	Glacier Gas	This Year Montana	Last Year Montana	%Change
151	Fuel Stock					
152	Fuel Stock Expenses Undistributed					
153	Residuals	$0		$0		
154	Plant Materials & Operating Supplies					
	Assigned and Allocated to;					
	Operation & Maintenance					
	Construction					
	Production Plant	29,919		29,919	$1,623,503	-98.16%
	Transmission Plant	1,160,226		1,160,226	830,680	39.67%
	Distribution Plant	1,793,258		1,793,258	1,227,661	46.07%
155	Merchandise					
156	Other Materials & Supplies					
157	Nuclear Materials Held for Sale					
163	Stores Expense Undistributed	0		0		
TOTAL MATERIALS & SUPPLIES		$2,983,403	$0	$2,983,403	$3,681,844	-18.97%

Sch. 22

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - NATURAL GAS

	% Capital Structure	% Cost Rate	Weighted Cost
Commission Accepted - Most Recent			
Docket Number: D96.2.22			
Order Number : 5898d			
Common Equity	44.34%	11.25%	4.99%
Preferred Stock	4.29%	6.40%	0.27%
QUIPs Preferred 2/	4.66%	8.77%	0.41%
Long Term Debt	46.71%	8.04%	3.76%
TOTAL	100.00%		9.43%
Actual at Year End			
Common Equity	44.25%	11.25%	4.98%
Preferred Stock	4.99%	6.40%	0.32%
QUIPS Preferred 1/	5.62%	8.54%	0.48%
Long Term Debt 2/	45.14%	7.81%	3.53%
Other			
TOTAL	100.00%		9.31%

1/ Docket 96.2.22, Order 5898d 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 can not 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.

Sch. 26

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 - NATURAL GAS

		Description	Last Year	This Year	% Change
1		**Rate Base**			
2	101	Plant in Service	$344,303,197	$360,909,980	4.82%
3	108	Accumulated Depreciation	(112,784,957)	(121,807,785)	-8.00%
5	**Net Plant in Service**		$231,518,240	$239,102,195	3.28%
6		Additions:			
7	154, 156	Materials & Supplies	$4,201,224	$3,316,499	-21.06%
8	165	Prepayments	(64)	0	100.00%
9		Other Additions 1/	92,498,550	57,603,007	-37.73%
11	**Total Additions**		$96,699,710	$60,919,506	-37.00%
12		Deductions:			
13	190	Accumulated Deferred Income Taxes 1/	$35,817,218	$37,758,397	5.42%
14	252	Customer Advances for Construction	2,271,542	2,919,585	28.53%
15	255	Accumulated Def. Investment Tax Credits	0	0	0.00%
16		Other Deductions 1/	6,427,900	24,429,076	280.05%
18	**Total Deductions**		$44,516,660	$65,107,058	46.25%
19	**Total Rate Base**		$283,701,290	$234,914,643	-17.20%
20	**Net Earnings**		$14,645,232	$12,517,694	-14.53%
21	**Rate of Return on Average Rate Base**		5.162%	5.329%	3.22%
22	**Rate of Return on Average Equity 2/**		0.639%	0.301%	-52.90%
24		**Major Normalizing and**			
25		**Commission Ratemaking Adjustments**			
26		Removal of Gas Securitization Activity	0	18,498	-
27		Rate Schedule Revenues	$2,360,715	$4,165,666	76.46%
29		Non-Allowables:			
30		Advertising	415,537	200,276	-51.80%
31		Benefit Restoration Plan	630,559	162,267	-74.27%
32		Dues, Contributions, Other	17,621	14,890	-15.50%
33		Corporate Overhead	20,180	77,456	283.83%
34		Associated Income Taxes	(1,356,747)	(1,827,207)	-34.68%
35	**Total Adjustments**		$2,087,865	$2,811,846	34.68%
36	**Revised Net Earnings**		$16,733,097	$15,329,540	-8.39%
37	**Adjusted Rate of Return on Average Rate Base**		5.898%	6.526%	10.64%
38	**Adjusted Rate of Return on Average Equity 2/**		2.347%	3.006%	28.08%

1/ Includes adjustments related to FAS 109.

2/ The 1999 ROE calculation utilizes the common equity component on Sch. 22 of this Report, applied to rate base for the denominator of the equations. The 1998 common equity component applied to rate base was 43.10%.

Sch. 27

MONTANA EARNED RATE OF RETURN - NATURAL GAS

Description	Last Year	This Year	% Change
Detail - Other Additions			
FAS 109 Regulatory Asset	$9,456,818	$11,135,290	17.75%
Gas Stored Underground	44,668,830	45,244,689	1.29%
Plant Held For Future Use	(80)		100.00%
Conservation Expenditures	336		-100.00%
Cost of Refinancing Debt	1,252,160	1,002,472	-19.94%
1994 Severance Plan	59,099	59,099	0.00%
1995 and 1996 Severance Plans	144,736	144,736	0.00%
Division Centralization	16,721	16,721	0.00%
CTC - GP	30,583,732		-100.00%
CTC - RA	6,316,198		-100.00%
Total Other Additions	$92,498,550	$57,603,007	-37.73%
Detail - Other Deductions			
Personal Injury and Property Damage	$639,515	$664,474	3.90%
Deferred Taxes - CIAC			-
Unamortized Gain on Reacquired Debt			-
Gross Cash Requirements	4,381,881	4,725,902	7.85%
Assets Sales			-
Bond Refinancing CTC - GP	336,084	4,369,094	1200.00%
Bond Refinancing CTC - RA	1,070,420	13,915,459	1200.00%
Deferred Storage Gas Sales		754,147	
Total Other Deductions	$6,427,900	$24,429,076	280.05%

Sch. 28

MONTANA COMPOSITE STATISTICS - NATURAL GAS (INCLUDES CMP)

	Description	Amount
	Plant (Intrastate Only)	
101	Plant in Service (Includes Allocation from Common)	$367,403,287
105	Plant Held for Future Use	8,984
107	Construction Work in Progress	235,913
117	Gas in Underground Storage	44,877,231
151-163	Materials & Supplies	2,983,403
	(Less):	
108, 111	Depreciation & Amortization Reserves	124,061,967
252	Contributions in Aid of Construction	3,241,425
NET BOOK COSTS		$288,205,426
	Revenues & Expenses	
400	Operating Revenues	$104,273,704
Total Operating Revenues		$104,273,704
401-402	Other Operating Expenses	$68,454,429
403-407	Depreciation & Amortization Expenses	9,214,400
408.1	Taxes Other than Income Taxes	14,255,860
409-411	Federal & State Income Taxes	(168,679)
Total Operating Expenses		$91,756,010
Net Operating Income		$12,517,694
415-421.1	Other Income	$934,380
421.2-426.5	Other Deductions	(418,080)
NET INCOME BEFORE INTEREST EXPENSE		$13,033,994
	Average Customers (Intrastate Only)	
	Residential	129,888
	Commercial	17,892
	Industrial	398
	Other	46
TOTAL AVERAGE NUMBER OF CUSTOMERS		148,224
	Other Statistics (Intrastate Only)	
	Average Annual Residential Use (Mcf)	97
	Average Annual Residential Cost per (Mcf)	$4.77
	Average Residential Monthly Bill	$38.76
	Plant in Service (Gross) per Customer	$2,479

City	Population 7/1/98 Estimates	Residential	Commercial	Industrial & Other	Total
Absarokee		444	77	2	523
Amsterdam		1			1
Anaconda	9999	3418	331	4	3753
Augusta		186	42	1	229
Barber		3			3
Belfry		5			5
Belgrade	5018	2454	337	2	2793
Big Mountain		87	18		105
Big Sandy	698	306	83		389
Big Timber	1689	828	168	9	1005
Billings	91750	29	23	1	53
Boulder	1654	463	78		541
Bozeman	29936	12808	1867	18	14693
Browning	1208	979	148	2	1129
Butte	33994	12782	1322	54	14158
Carter		30	9		39
Chester	959	384	122	4	510
Chinook	1590	728	144	7	879
Choteau	1802	841	172	5	1018
Clancy		1026	63	2	1091
Clinton		350	15	1	366
Columbia Falls	4205	2636	291	4	2931
Columbus	2072		955	133	7
Conrad	2903	1190	207	20	1417
Coram		115	18		133
Corbin-Jefferson		99	8	2	109
Corvallis		712	73	1	786
Deer Lodge	3700	1592	193	6	1791
Dillon	4267	1930	325	8	2263
Drummond	278	263	75	2	340
East Glacier		121	49	1	171
East Helena	1750	1584	92	4	1680
Elliston		89	12		101
Fairfield	681	399	87	5	491
Florence		898	55	1	954
Floweree		44	8		52
Fort Benton	1613	607	159	1	767
Fort Shaw		104	12		116
Gallatin Gateway		152	27		179
Garrison		23	5		28
Gildford		85	28	1	114
Great Falls	56395	1183	102	6	1291
Greycliff		43	6		49
Hamilton	4463	3230	535	10	3775
Harlem	982	646	124	2	772

Harlowtown	1097	537	84	2	623
Havre	10015	4528	597	8	5133
Helena	28306	14431	2004	44	16479
Hingham	174	89	31		120
Hungry Horse		240	39		279
Iverness		42	14		56
Joplin		105	28		133
Judith Gap	144	73	9		82
Kalispell	16089	8721	1531	21	10273
Kremlin		61	14		75
Laurel	6027	10			10
Lewistown	6159	2805	434	14	3253
Livingston	7348	3573	489	20	4082
Logan		2			2
Lohman		2	1		3
Lolo		1263	79		1342
Loma		39	18		57
Manhattan	1423	1047	118	2	1167
Martin City		109	18		127
Missoula	52239	24532	3072	70	27674
Philipsburg	971	1511	215	36	1762
Red Lodge	2238	1442	245	6	1693
Reedpoint		80	15		95
Rudyard		138	33		171
Shawmut		25	3		28
Sheridan	733	363	61		424
Simms		167	17	1	185
Somers		204	17		221
Springdale		2			2
Stevensville	2046	1235	196	6	1437
Sun River		111	19		130
Three Forks	1528	699	111	1	811
Trident		2			2
Twin Bridges	429	216	55		271
Valier	544	78	12	1	91
Vaughn		341	28	1	370
Victor		423	65	1	489
West Glacier		158	47	3	208
Whitefish	5875	2779	401	4	3184
Whitehall	1399	705	113	4	822
Willow Creek		95	11		106
Wolf Creek		48	24	1	73

Sch. 30

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.

Sch. 31

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

Sch. 32

TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS

		Transmission System-Sales and Transportation					
		Peak Day of Month		Peak Day Volume(Mcf@14.9)		Monthly Volumes(Mcf@14.9)	
	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
1		NOT AVAILABLE				2/	3/
2	January					5,628,409	4,308,187
3	February					4,328,912	3,907,614
4	March					3,966,630	3,808,375
5	April					3,315,449	3,362,738
6	May					2,711,897	2,992,732
7	June					1,678,328	2,771,210
8	July					1,546,267	2,165,133
9	August					1,417,332	2,465,343
10	September					2,108,124	2,461,131
11	October					3,054,874	2,553,911
12	November					4,000,295	3,554,833
13	December					5,232,573	3,911,950
14	TOTAL					38,989,090	38,263,157
15		**Distribution System-Sales and Transportation**					
16		Sales Volumes		Transportation Volumes		Monthly Volumes(Mcf@14.9)	
17	Month	Total Company	Montana	Total Company	Montana	Total Company	Montana
18			1/		1/	4/	5/
19	January	2,979,107		272,296		3,251,403	2,979,107
20	February	2,443,873		248,588		2,692,461	2,443,873
21	March	2,072,747		216,559		2,289,306	2,072,747
22	April	1,737,781		211,497		1,949,278	1,737,781
23	May	1,305,400		183,231		1,488,631	1,305,400
24	June	747,214		143,694		890,908	747,214
25	July	518,070		104,724		622,794	518,070
26	August	403,715		88,802		492,517	403,715
27	September	601,941		83,973		685,914	601,941
28	October	1,047,812		118,906		1,166,718	1,047,812
29	November	1,456,789		165,948		1,622,737	1,456,789
30	December	2,205,286		188,865		2,394,151	2,205,286
31	TOTAL	17,519,735		2,027,083		19,546,818	17,519,735
32		**Storage System-Sales and Transportation**					
33		Peak Day & Peak Day Vol.		Total Monthly Volumes(Mcf@14.9)			
34	Month	Total Company	Montana	Total Company 4/		Montana 5/	
35		1/	1/	Injection	Withdrawal	Injection	Withdrawal
36	January			16,503	1,838,615	0	1,001,933
37	February			37,444	1,211,844	0	661,982
38	March			139,684	797,874	0	172,938
39	April			660,841	728,412	0	193166
40	May			957,848	221,110	245,885	0
41	June			1,307,962	41,757	601,671	0
42	July			1,343,485	31,693	633,946	0
43	August			1,644,496	38,908	1,043,325	0
44	September			790,815	327,270	686,308	0
45	October			370,544	705,839	0	61,982
46	November			292,080	949,822	151,985	0
47	December			18,986	1,214,590	0	590,462
48	TOTAL			7,580,688	8,107,734	3,363,120	2,682,463

49 1/ Data is not accumulated on a daily basis, therefore the peak day and peak day volumes are not available.
50 2/ Includes intrastate and interstate deliveries.
51 3/ Includes intrastate deliveries only.
52 4/ Includes sales and transportation volumes. Losses of gas are not available.
53 5/ Includes sales volumes only. Losses of gas are not available.

Sch. 33	SOURCES OF CORE NATURAL GAS SUPPLY				
	Name of Supplier	Last Year Volumes Mcf	This Year Volumes Mcf	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2	Montana Purchase	6,183,408	5,940,007	$1.6890	$1.9250
3	Montana Royalty	0	0	0.0000	0.0000
4	MP Gas	10,956,279	10,517,147	1.7380	1.5820
5	Rosza	283,154	342,523	1.5240	1.8900
6	Blaine #3	831,260	917,122	1.8180	1.9640
7	Canadian Purchase	0	0	0.0000	0.0000
8	Canadian Royalty	0	0	0.0000	0.0000
9	Reagan	0	0	0.0000	0.0000
10	Carway	1,493,294	798,360	2.0250	2.4370
11	**TOTAL CORE SUPPLY**	19,747,395	18,515,159	$1.7228	$1.7186
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Sch. 3

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS - NATURAL GAS 1/

Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings Mcf	Achieved Savings Mcf	2/ Difference
Residential E+ Audits - 3/	$851,219	$309,545	174.99%	N/A	11,596	11,596
Free Weatherization (Low income) 3/	162,613	562,745	-71.10%	N/A	7,791	7,791
TOTAL	$1,013,832	$872,290	16.23%	0	19,387	19,387

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/ Planned Savings and Achieved Savings are reported in Net MCFs.

3/ Expenditures through October 1997. Effective November 21, 1997, Gas conservation programs were assigned to the CTC-RA (Competitive Transition Charge - Regulatory Assets) per MPSC Order 5898d. Small Commercial audit pilot program results are included.

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 spent in 2000, 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, revewable 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

MONTANA CONSUMPTION AND REVENUES - NATURAL GAS (EXCLUDES GLACIER GAS)

	Operating Revenues		MCF Sold		Average Customers	
	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
Sales of Natural Gas						
Residential	$60,420,611	$61,446,308	12,657,878	12,929,818	129,888	126,962
Commercial	27,376,692	30,120,125	5,618,834	6,367,818	17,892	17,581
Industrial Firm	1,254,911	1,371,859	281,461	308,500	398	394
Public Authorities	-11,586	237,205	-27,020	58,013	8	9
Interdepartmental	198,189	201,366	39,088	41,511	37	32
CNG Station	10,469	16,569	3,035	6,174		
Sales to Other Utilities	611,451	606,470	228,729	189,094	1	3
TOTAL SALES	$89,860,737	$93,999,902	18,802,005	19,900,928	148,224	144,981

	Operating Revenues		Dkt Transported		Average Customers	
	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
Transportation of Gas						
Firm - DBU	$1,690,808	$1,901,082	3,184,167	2,529,920	214	211
Firm - S & TBU	7,408,536	7,860,701	11,631,664	12,288,029	19	19
Interruptible - DBU	19240	40,985	163,954	122,365	5	3
Interruptible - S & TBU	712476	1,173,108	5,096,505	5,481,212	1	1
Interruptible - Off System	1,945,988	2,005,590	4,565,454	6,743,269		
Sales Subscriptions						
Firm - GTAC Refund						
Interruptible - GTAC Balance						
Gathering & Processing						
Storage	2,079,928	2,368,767				
TOTAL TRANSPORTATION	$13,856,976	$15,350,233	$24,641,744	$27,164,795	239	234